5.0 PIPELINE INTEGRITY ANALYSIS

5.1 BACKGROUND AND PURPOSE

This chapter discusses the operational practices and physical attributes directly affecting the system integrity of the Longhorn Pipeline System (System). Operational procedures govern the overall quality of operating and maintenance activities. Proposed procedures of Williams Energy Services (WES), Longhorn Partner's Pipeline, L.P. (Longhorn) operating contractor, are examined. This evaluation of procedures and conditions, referred to as the Pipeline Integrity Analysis (PIA), examines the overall approach to operations and condition of the System and its ability to transport refined petroleum products safely with regard to people and the environment.

Included in this discussion is an overall summary of the pipeline's general attributes, including a review of data from past inspections and testing. These data are used for determining the structural integrity of the pipeline as well as the System's ability to withstand specified operating pressures. This chapter also evaluates the pipeline's leak history, including a review of spill incidents, frequencies, volumes, causes, and a comparison with other pipeline event data under Exxon Pipeline Company (EPC) operation.

Additionally, this chapter reviews spill response procedures focusing on compliance and consideration of sensitive areas. A review of the Year 2000 (Y2K) Compliance Plan, as it relates to pipeline operation, is also examined. A summary of major findings concludes the chapter. The analysis of this chapter provides the foundation for the risk assessment work of Chapter 6.

As a result of the Settlement Agreement (Settlement), topics comprising the PIA include those listed below. Where reference is made to Longhorn, except for asset ownership, all operational aspects actually apply to WES, as the operating contractor.

The PIA includes:

1) Review of the compliance of the existing pipeline, new facilities, and testing of the pipeline with governmental safety standards for operation of oil pipelines, industry standards, and sound engineering practice.

2) Consideration of:

    - Inspection, test records, and test methods (e.g., cathodic protection [CP] tests, Internal Line Inspection [ILI] [smart pig tests], depth of cover data, "fly-over" records, Office of Pipeline Safety [OPS] inspections and audits, hydrostatic tests);

- Maintenance records;
- Leak history of the existing pipeline, including pinhole leaks, line ruptures, third party accidents;
- Aging effects on pipeline;
- Pipeline repairs (e.g., clamps, replaced sections);
- Sections of pipeline manufactured using low frequency electric resistance welding process;
- Block and check valve placement and spacing; and
- Stability of river and creek crossings, including weld integrity, pipeline strength, depth of cover, characteristics of cover material, potential for washout, and erosion threats to aerial supports.

3) Review of the compliance of Longhorn's proposed operational procedures and Longhorn's spill/leak response measures with:

   - Governmental safety standards (e.g., Department of Transportation [DOT], Environmental Protection Agency [EPA]);
   - Industry standards (e.g., American Petroleum Institute [API], National Association of Corrosion Engineers [NACE]); and
   - Sound engineering practices.

4) Identification of any areas where Longhorn's facilities, testing, operational standards and procedures, and response measures identified in Item 3 above are not consistent with industry standards or sound engineering practices. Any such identification specifies the industry standards or sound engineering practices sufficient to reasonably protect health, safety, and the environment that Longhorn has failed to meet, the appropriate and reasonable mitigation measures available to Longhorn to remedy any such failures and the anticipated benefit associated with each such mitigation.

5) Review of spill/leak response measures, including examination of the following:

   - Proposed leak detection system;
   - Procedures for pipeline sections considering resources at risk and reasonably available and proven technologies;
   - Shut-down decision process and timing;
   - Level and type of pipeline surveillance for pipeline sections considering resources at risk;
   - Staffing and equipment for spill response considering resources at risk;

- Clean-up standards and recovery plans considering resources at risk, including soil, surface water, ground water, threatened and endangered species; and
- Other components of the Oil Pollution Act of 1990 (OPA '90) Plan.

6) Identification of noncompliance with any current governmental safety standards.

7) Evaluation of whether Longhorn's computers for pipeline operations are Y2K compliant.

The data gathering and analysis required to meet the foregoing requirements not only provide an indication of pipeline integrity, but also provide data needed in the risk assessment included in Chapter 6. The issues addressed are numerous and data are extensive. Of necessity, engineering judgment was required in some cases to select a representative sampling of data and information to satisfy the priority needs of this study. An attempt was made to resolve competing assertions and interpretations of data as they exist for this pipeline and in the industry and community in general. In some cases, these issues cannot be resolved since even experts are divided on exact interpretation of the data and remedies. Current state-of-the-art practices have been reviewed and engineering judgments used to evaluate the integrity of the system.

At the time of this study, plans and actions for refurbishment, new construction and operation of the system were still in progress. For example, some operational procedures associated with the Longhorn Integrity Management System (LIMS) were still in development and therefore unavailable for review in detail. Clearing some portions of the right-of-way (ROW), and actions concerning some exposed pipe remained to be completed. In such cases, the evaluation was based on plans rather than existing conditions. As discussed under various topics in the remainder of this report, specific actions are planned for completion prior to or within a short period after startup.

The remainder of this chapter examines operational procedures, including maintenance, and those features of the physical system that determine system integrity. In these discussions, the implications of past practices of EPC on future system integrity are recognized. Operational procedures are discussed in Section 5.2. The effects of proposed operations by WES, the operating contractor for Longhorn, are examined. After the discussion of procedures, findings of past inspections and tests and on the condition of the physical system are covered in Section 5.3. Pump station issues are discussed in Section 5.4. Spill and leak response plans and the adequacy of such plans to prevent or mitigate damage from loss of containment are discussed in detail in Section 5.5. Section 5.6 discusses Y2K issues and Section 5.7 discusses Leak History.

5.2 OPERATIONAL PROCEDURES

This section discusses the evaluation of Longhorn's proposed operational procedures and standards to determine if they comply with governmental safety and regulatory requirements, and are consistent with industry standards and sound engineering practices as required by the Settlement Agreement. Activities associated with both the pipeline and pump stations are noted. The WES System of Operating Manuals is discussed. This includes a review of procedures addressing topics or issues of concern as identified by the plaintiffs' and other public comments.

Pipeline

Activities associated with the operation and maintenance of the pipeline include the following:

- Maintenance of valves, motors, pumps, flow meters, instrumentation, electrical, supervisory control system, and communications;
- Inspection and maintenance of CP systems;
- Inspection of block valves to ensure proper operation and site maintenance;
- Calibration of all instrumentation to comply with company standards, manufacturers recommendations, and applicable state and federal regulations;
- Inspection and maintenance of pipeline mileage and pipeline location markers;
- Surveillance of ROW for encroachments and physical condition; observation of all construction activities, by others, on or near the Longhorn ROW; locating exposed pipe;
- Inspection of river and stream crossings and crossings of Longhorn pipeline by other pipelines, highways and utilities; and
- Building relationships with landowners, local communities, and customers.

Pump Stations and El Paso Terminal

Activities associated with the operation and maintenance of the station and terminal, as applicable, include the following:

- Maintenance of valves, motors, pumps, flow meters, instrumentation, electrical, supervisory control and communications;

- Truck driver safety training and certification;
- Daily tank farm safety inspection and maintenance;
- Daily truck loading rack safety inspection and maintenance;
- Maintenance of Vapor Combustion Unit (VCU);
- Refined product receipts, sampling and testing;
- Regulatory recordkeeping;
- Observation of all construction activities, by contractors, within El Paso Terminal; and
- Building relationships with local communities and customers.

The review of operating procedures was accomplished by two methods. First, compliance checklists were developed for the applicable regulations and industry standards. The checklists shown in Appendices 5A, 5B, and 5C, note the section(s) from Longhorn's manuals that addresses each of the requirements. This type of review is consistent with regulatory audits of procedures. The second review method involved a more detailed examination of Longhorn's manuals and procedures with respect to key issues identified through plaintiff and public comments. WES's current practices and proposed practices for the Longhorn pipeline that exceed requirements are discussed.

5.2.1 Basis for Operational Procedures

DOT requires that liquid pipeline companies prepare and follow a manual of written procedures for conducting normal operations and maintenance activities and for managing abnormal operations and emergency situations. To meet this requirement, Longhorn has adopted the WES System of Operating Manuals for liquid pipelines.

Operation and maintenance of the System will follow the guidelines set forth in the manuals. These manuals are being adopted from the WES' liquids pipeline manuals. The following volumes comprise the System of Operating Manuals:

- Chemical Hazard Communication/Chemical Hygiene Plan;
- Emergency Response Plan (ERP);
- Maintenance and Calibration;
- Measurement;
- Oil Spill Response Plan;
- On-the-Job Training Program – Maintenance Crew;

- On-the-Job Training Program – Pipeline Operators;
- Operating Manual;
- Operations Control/Dispatcher Procedures;
- Preventive Maintenance;
- Safety; and
- Welding and Radiographic Procedures.

The WES manuals address written procedures for conducting normal operations and maintenance activities and for handling abnormal operations and emergencies. The manuals address DOT, Occupational Safety and Health Administration (OSHA), EPA, and/or company requirements. The System of Manuals consists of 12 individual volumes of information, which are listed and summarized in the following paragraphs.

Williams Energy Services Chemical Hazard Communication/Chemical Hygiene Plan. The Chemical Hazard Communication Program (HAZCOM) provides information for all employees who have potential on-the-job exposure to hazardous chemicals. The program complies with the requirements of OSHA, 29 Code of Federal Regulations (CFR) §1910.120. The program includes an overview of the OSHA standard, hazardous properties of chemicals in the form of material safety data sheets (MSDS) and container labeling, safe handling procedures, and measures of personal protection.

Williams Energy Services Maintenance and Calibration. This manual deals with technical aspects of equipment, controls, and circuitry. It provides control limits for pumping operations. The manual contains maintenance inspection lists, which address periodic testing of safety and control devices.

Williams Energy Services Measurement. This manual addresses the measurement of product volume and characteristics through the pipeline system, including storage tanks, piping, pumping, and transfer. The manual includes physical properties, normal operations, design criteria, maintenance, and appendices.

Williams Energy Services Oil Spill Response Plan. The oil facility response plan (FRP) provides protocols and procedures to be followed in the event of a spill from the Longhorn pipeline. The purpose of the plan is to minimize potential oil spill and mitigate effects of oil spills. Preventative measures include securing the source of the release, containing it as close to the source as possible, protecting threatened, environmentally sensitive and economically important areas, and removing the oil and oily debris as quickly as possible. The manual is written to comply with 49 CFR Part 194. Along with procedures, the manual includes descriptions of the chain of command and organizational lines of authority; job assignments, duties, and responsibilities; and available resources for quick and efficient response.

***Williams Energy Services Maintenance Crew On-the-Job Training (OJT) Program*.** The Maintenance Crew OJT Program provides training for maintenance crew employees. The program includes both knowledge-based training (i.e., computer-based module training and safety training) and skill-based training procedures. The Maintenance Crew program includes specific written procedures on safety skills, mainline skills, (which cover skills on locating, inspecting, testing the mainline pipe); and general skills that cover the testing, response, and cleanup of leaks and spills of lines and use of equipment to access mainlines. The manual also includes checklists for recording the training of employees.

***Williams Energy Services OJT Program – Pipeline Operators*.** The Operator OJT Program provides training for station and terminal operators. The program includes both knowledge-based and skill-based training procedures. The program includes written procedures on safety skills, general skills on the operation of tank farms, computer operations, pumping unit operations, station/terminal manifold operations, tank operations, metering, and rack operations. The manual also includes checklists for recording the training of employees.

Williams Energy Services Operating Manual. This manual contains information on normal, abnormal, and emergency operating procedures. Major topics in the manual are as follows:

- Hazardous materials handling;
- Tankage;
- Product handling;
- Manifolds;
- Mainlines;
- Pumping stations;

- Recovery systems;
- Terminals;
- Buildings and grounds;
- Materials and supplies;
- Waste handling guidelines;
- Training;
- Liquid petroleum gases (LPG);
- Crude oil;
- Special instructions on internal corrosion control;
- Capital and project expense budgeting;
- Company vehicle and tractor standards;
- 49 CFR Part 195; and
- Safety reporting.

Williams Energy Services Operations Control/Dispatcher Procedures. This manual includes written procedures for the operations and control of the pipeline. The procedures include normal, abnormal, emergency, maintenance, and pressure settings of tanks, mainline valves, pumps, and surge relief systems. The manual also includes startup and shutdown procedures for pump stations. Forms to track the operations and controls are included in the manual.

Williams Energy Services Preventative Maintenance. This manual covers the inspections of pipeline operating equipment performed on a regular cycle by trained employees. Inspections may require routine maintenance or emergency repair to rectify situations found. The manual covers inspections required at various frequencies including weekly, monthly, quarterly, semiannually, tri-annually, annually, and biannually. The manual includes inspection and maintenance instructions, frequencies, checklists, and forms.

Williams Energy Services Safety. This manual covers safety modules, which comply with governing federal, state, and local occupational safety and health laws, rules, and regulations. The procedures also address issues of industry standard practice. Topics covered include design, construction, and operation of the pipeline facilities. The procedures are in place to prevent employee injury, operational loss, and property damage.

Williams Energy Services Welding and Radiographic Procedures. This manual includes specifications and procedures to be used for construction, fabrication, and maintenance of all company operated piping systems. The manual also includes procedures for tank welding applications, magnetic particle testing, visible dye penetrant testing (PT), arc burn removal, and safety considerations, along with corresponding forms and records.

Each of the manuals listed above was reviewed with respect to meeting regulatory requirements as well as industry recommendations and sound engineering practices for operational and maintenance procedures. All references to the manuals will be assumed to have "Williams Energy Services" in the title.

5.2.2 Applicable Regulations

The Longhorn pipeline is governed by federal regulations. Railroad Commission of Texas (RRC), Oil and Gas Division regulates the production and transport of oil and gas within the State of Texas. However, the Longhorn pipeline is an interstate rather than intrastate system, and therefore, falls under federal jurisdiction. Applicable federal regulations are listed and described below:

- ***Pipeline Safety Regulations***. 49 CFR Parts 40, 190, 194, 195 and 199 are applicable to liquid pipelines. Part 40 prescribes procedures for drug and alcohol testing. Part 190 prescribes procedures used by the OPS for regulating pipeline safety. The enforcement authority of OPS and civil and criminal penalties for violating the Hazardous Liquid Pipeline Safety Act are detailed in this regulation. Part 194 contains requirements for oil spill response plans to reduce the environmental impact of onshore pipeline oil spills. Longhorn procedures and practices relative to this regulation are discussed under Section 5.5 of this chapter. Part 195 prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids. Part 199 addresses the requirements for drug and alcohol testing and references the procedures of Part 40.
- ***National Oil and Hazardous Substance Pollution Contingency Plan***. EPA 40 CFR Part 300 provides an organizational framework and procedures for preparing to respond to discharges of oil and accidental releases of hazardous substances into locations which present danger to public health or welfare. The document specifies responsibilities among federal, state, and local regulatory agencies during an emergency response. It establishes requirements for federal,

regional, and area emergency response plans and addresses procedures for the response of other persons as well. This document also provides response plans per Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) requirements. The evaluation of Longhorn's procedures relative to this regulation is discussed in Section 5.5 of this chapter.

- ***Hazardous Waste Operations and Emergency Response (HAZWOPER).*** OSHA 29 CFR §1910.120 covers HAZWOPER activities. Hazardous waste activities include clean-up operations required by a governmental body involving hazardous substances at uncontrolled hazardous waste sites; corrective actions involving clean-up operations at Resource Conservation and Recovery Act (RCRA) sites; voluntary clean-up operations at sites recognized by governmental bodies as uncontrolled waste sites; and operations involving hazardous wastes at treatment, storage, and disposal facilities. Emergency response operations for releases of hazardous materials comply with requirements of paragraph (q) of this regulation. The evaluation of Longhorn's procedures relative to this regulation is discussed in Section 5.5 of this chapter.

Longhorn pipeline operation and maintenance procedures were reviewed against regulatory requirements in 49 CFR Part 195. A checklist of items reviewed is provided in Appendix 5A. Regulatory topics related to Emergency Response are discussed in more detail in Section 5.5. Items listed in Table 5-1 are areas where regulatory requirements are met in documents outside of the System of Operating Manuals.

EPC Regulatory Compliance History

Although RRC does not have jurisdiction over interstate pipeline operations, under a temporary interstate agreement with DOT, the agency performed a safety evaluation of the EPC pipeline system in 1996, prior to acquisition by Longhorn. The evaluation included a review of the pipeline system's operating procedures and manuals and the review consisted of a checklist form indicating "Satisfactory," "Unsatisfactory," or "Not Applicable" for the items required by 49 CFR Part 195 Subpart F, *Operation and Maintenance*. The evaluation by RRC, ranked the EPC operating procedures and manuals "Satisfactory" for all items reviewed.

Two concerns were reported in a letter dated April 30, 1996, from RRC to DOT. The concerns were failure to maintain a test lead at a road crossing (US Highway 290, near Austin) and failure to reconnect a rectifier after the Kemper pump station was dismantled. A Letter of Concern was issued by DOT to EPC for correcting these conditions. These are being resolved as part of the System refurbishment. DOT records revealed no other issues of non-compliance.

5.2.3 Industry Standards

The intent of industry codes and standards is to improve the pipeline system by understanding the causes for failures and establishing guidelines, procedures, and methods for reducing pipeline failures. Many national codes and industry standards for pipelines and the transport of petroleum products are applicable to Longhorn's pipeline operations. For example, Table 5-2 lists the standards incorporated by reference into 49 CFR Part 195. These referenced documents, or portions of documents, are incorporated into the regulations as if they were printed in full. Therefore, pipeline operators must also abide by the requirements or recommendations of these codes and standards.

For the purpose of this evaluation, two standards were selected to review against Longhorn's operational procedures: American Society of Mechanical Engineers (ASME) B31.4 and API Recommended Practice 1129. ASME B31.4, *Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols*, sets forth the engineering requirements deemed necessary for safe design and construction of pressurized piping. The primary purpose of this code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public and operating personnel as well as for reasonable protection of the piping system and the environment. API Recommended Practice 1129, *Assurance of Hazardous Liquid Pipeline System Integrity*, is a basic guide and resource to provide increased assurance of a pipeline system's integrity. The purposes are to compile a wide base of current industry experience, knowledge, information, and management practices into a cohesive document comprising a range of best practices and to assist pipeline operators in increasing the integrity of their pipeline systems.

Longhorn's operational procedures were checked against the requirements of ASME B31.4 and API Recommended Practice 1129, respectively. Checklists are provided in Appendix 5B and 5C. Topics that are covered in Longhorn's Emergency Response manual are discussed in Section 5.5.

A few topics that did not appear to be explicitly addressed in the System of Operating Manuals are listed in Table 5-3.

5.2.4 Sound Engineering Practices

"Sound engineering practices" is a generic tag applied to various good practices used in the industry, which may or may not be formally codified. Table 5-4 lists selected major topics related to operating procedures. The table indicates where these topics are covered in the various regulations and standards as well as where Longhorn's procedures address these topics.

Longhorn has performed, and has committed to make, additional improvements to the System. These commitments, described below, have been considered in this Environmental Assessment (EA). These measures, being conducted in 1998 and 1999, include an integrity audit and depth of cover, exposed pipe, and close interval surveys. Other commitments are discussed in Chapter 9 on mitigation measures.

Integrity Audit

An integrity audit was conducted by John Kiefner of Kiefner and Associates, Inc. (Johnston, 1999). Mr. Kiefner is recognized in the pipeline industry as a leading authority on pipe integrity and metallurgy. The audit report states that the Longhorn pipeline is suitable for its intended service with an acceptably low potential for releases, provided the audit report's recommendations are implemented. Longhorn has committed to implementing the recommendations (Longhorn, 1999).

Surveys

Surveys that were recently performed include:

- Depth of Cover Survey;
- Exposed Pipe Survey; and
- Cathodic Protection (CP)/Close Interval Survey (CIS).

These surveys have provided data for Longhorn's Risk Assessment and Integrity Management programs, which are currently under development. They also have provided Longhorn with data to design and implement corrective actions, and to identify and resolve potential issues. Findings from the surveys have provided Longhorn with information to design and implement a risk management program, which specifically addresses these findings and monitors integrity and condition on an ongoing basis.

Longhorn Integrity Management System (LIMS)

Overriding all aspects of operations will be LIMS. The LIMS Expectation and Guidelines is a framework for the developing LIMS. The purpose of LIMS, consistent with recent trends in the hydrocarbon industrial sector, is to provide an overall environmental, health and safety management system as an operating framework into which all procedures, practices, and activities fit so that they achieve explicitly defined performance objectives of management in these areas. The philosophical context of such a system is similar to the International Standards Organization (ISO) 9000 quality standard and ISO 14000 environmental management standard. It is also consistent with Environmental Health and Safety (EHS) management systems developed within the petroleum industry during the last decade by firms such as Exxon, Chevron, and Mobil. The framework is comprised of ten elements including the following:

- Element 1: Management, Commitment, and Accountability;
- Element 2: Risk Assessment and Management;
- Element 3: Facilities Design and Construction, Operations, Maintenance, and Emergency Preparedness/Response;
- Element 4: Information Systems and Documentation;
- Element 5: Human Resources/Training;
- Element 6: Management of Change;
- Element 7: Outsourced Services;
- Element 8: Incident Investigation and Analysis;
- Element 9: Community Awareness and Outreach; and
- Element 10: Operations Integrity Assessment and Improvement.

For each element, there is a principle and a corresponding set of expectations for conducting Longhorn activities.

As operator of the pipeline, WES plans to implement a set of processes which conform to the LIMS expectations. In addition, the processes will also conform to the WES Operations and Technical Services Group (OTS) strategies which include the OSHA Process Safety Management (PSM) program in the areas of operational excellence. The anticipated release date of these documents has not been established.

Within the overall operational procedure framework just discussed, specific procedures related directly to major pipeline system integrity factors were reviewed. These categories of procedures deal with:

- Damage prevention;
- Corrosion control;
- Leak detection;

- Surge control and overpressure protection;
- Fatigue monitoring;
- Crossings;
- Staffing; and
- Training.

Formal Risk Assessment and Management

Risk assessments performed for the system are discussed in Chapter 6. The following discussion addresses risk assessment and management as a Longhorn operating program. Longhorn states that it is committed to constructing, operating, and maintaining its pipeline assets in a manner that:

- Ensures long-term safety to the public and Longhorn employees; and
- Maximizes environmental protection.

Each pipeline system has unique characteristics and presents unique challenges in meeting these objectives. Longhorn uses a risk management approach to manage these objectives. Risk management as defined by DOT sponsored Liquid Risk Assessment Quality Team as:

> "The overall logical process by which a company understands the risk associated with the operation of its facilities (risk assessment) and determines whether and how to take action to reduce or accept these risks (risk management)."

Two factors govern a company's risk level: the probability of an event and its consequence. Longhorn states that through the risk management process, Longhorn will implement controls to reduce the likelihood of adverse events and to mitigate the potential consequences.

Five-Year Program

Longhorn will further evaluate the findings of the Depth of Cover and Exposed Pipe Surveys on the basis of relative risk under a five-year program. The relative risk of exposed pipe and shallow cover will be based upon the likelihood of the hazard occurrence and the severity of potential consequences. Longhorn will evaluate third-party damage potential, corrosion probability, pipeline design characteristics and theoretical operational upsets. This five-year program will be continually evaluated in connection with the LIMS. Risk assessments conducted as part of the LIMS may compel a periodic reordering of risk management priorities.

Risk Model

Longhorn has adopted the WES' Relative Risk Assessment Model for its risk assessment process (Longhorn, 1999). This model, based on the work of W. Kent Muhlbauer (Muhlbauer, 1996) evaluates:

- Potential for third party damage;
- Probability of pipeline corrosion;
- Characteristics of pipeline design; and
- Possibilities of operations upsets.

Each factor is assigned a numerical index as outlined below.

- Third Party Damage Index - The Third Party Damage Index evaluates items such as depth of cover, activity level, one-call systems and public education.
- Corrosion Index - The Corrosion Index uses atmospheric, internal and buried metal corrosion attributes in its scoring.
- Pipeline Design Characteristics Index - Some of the characteristics under evaluation in the Pipeline Design Characteristics Index include pipe materials, hydrostatic testing, and design safety factors. The indexes are aggregated and weighted by a fifth index. This fifth index is developed with consideration for the types of product in the pipeline and the location of the pipeline relative to population and environmentally sensitive areas.
- Operations Upsets Index – An evaluation of operations and maintenance characteristics will consider issues such as operational complexity and maintenance history.

Risk Rankings

The pipeline system is divided into logical segments, as defined by the Muhlbauer Model, based upon the total risk characteristics of that segment as developed above. Overall, 55 data inputs for each segment of the pipeline will have been placed into the model. These segments are then ranked based on their score from the risk model. This allows for prioritization of pipeline segments based on their relative risks. Longhorn is presently implementing its Risk Assessment program, and database development is virtually complete.

According to Longhorn, the relative risk ranking results will be used to appropriately allocate resources to reduce Longhorn's overall operational risk. Benefits of an effective risk management program include: a sharper focus on continuously identifying and reducing real risk issues, reduction in accidents, prioritization of inspection programs, prioritization of maintenance plans, and assistance in project design. Risk management will provide a means to continuously evaluate the System.

5.2.5 Damage Prevention

The purpose of damage prevention is to protect the pipeline from third party interference. The Longhorn Damage Prevention Program includes public relations and patrol protocols. The protocols are described in Chapter 6 of the Operating Manual and Skill Numbers 2.17 and 2.18 of the Maintenance Crew OJT Manual Program. The public relations protocols address complaints, rewards for reporting leaks, lease-line responsibilities checklists, access to location of pipelines, encroachment, permits and agreements, owner/tenant relations during repairs, property with tile drainage systems, excavation one-call system, open ditch, backfilling, final operations, and abandonment. The lease line responsibilities checklists include sections on maintenance repair and use, regulatory and engineering record keeping, pipeline modifications, real estate and claims, taxes, insurance, and other issues.

Other aspects of the Longhorn pipeline operations relating to damage prevention include public education efforts, one-call, pipeline depth of cover, and pipeline markers. These topics are addressed in the following paragraphs.

Public Education/Communication—Public education procedures are also described on page 19.9 of the Operating Manual. This section describes a communication program with residents, community officials, and excavators along the pipeline ROW. The program is consistent with the requirements of 49 CFR §195.440. Components of the program include use of pipeline markers, participation in industry-sponsored public education efforts, distribution of safety brochures to residents and excavating contractors, one-call membership, and contacts and distribution made during routine operation and maintenance activities.

Longhorn plans to produce and distribute public education brochures on an annual basis (Longhorn, 1999). Distribution of the brochures would be developed using zip code/address cross reference databases and current maps. These brochures address various safety and public awareness topics such as how to identify and locate a pipeline, how to identify and respond to a pipeline release, when to contact a one-call system, and warnings concerning excavation, digging, and plowing near pipelines.

Specifically, these brochures would include the following information and topics:

- A brief explanation of the specific pipeline system (e.g., products transported, product end uses, etc.);
- A full color depiction of a pipeline marker sign;
- An explanation of pipeline marker signs, including the type of marker used, the information provided on the marker and where markers are normally located;
- A reminder to notify the appropriate one-call system prior to any digging, excavating, or plowing near the pipeline;
- The Texas One-Call System phone number;
- Longhorn's emergency toll-free phone number (1-888-465-9512);
- An explanation of how to recognize a pipeline release through the senses of sight, sound, and smell;
- A list of appropriate actions that should be taken in the event of a pipeline release;
- A full-color system map; and
- A request to pass the information along to family members and business associates.

To provide a comprehensive distribution to the appropriate audience, Longhorn has adopted the following target audience guidelines:

- Residential and Business Addresses—One-quarter (¼) Mile Wide Corridor Distribution: Brochures would be distributed to all residential and business addresses located within one-eighth mile each side of the pipeline systems.
- Excavators and Contractors—County-wide Distribution: Brochures would be distributed to all excavators and contractors with mailing addresses within each county where the pipeline system is located.
- Public Safety Officials, Local Emergency Planning Committees, Emergency Responders, Local Government Agencies and Public Officials—County-wide Distribution: Brochures would be distributed to all public safety officials, local emergency planning committees, emergency responders, local government agencies and public officials with mailing addresses within each county where the pipeline system is located.
- Bilingual versions (English /Spanish) of the brochures would be distributed along the Longhorn pipeline.

The Maintenance Crew OJT Program addresses informing and educating third parties on WES procedures. This training addresses typical reasons for informing and educating the public, communication methods available, and a list of forms and records required for documenting communications.

Community Outreach Program—Longhorn sponsors community outreach efforts that focus on the safety aspects of the pipeline. Longhorn employs a Safety Consultant for the State of Texas who travels throughout the State, concentrating on the communities along the route of the System. He meets regularly (at least annually) with local emergency preparedness groups to discuss the location of the line, products in the line, and how to deal with any emergency situation involving the pipeline. Longhorn would regularly conduct mock drills with these emergency response groups to better plan for emergency situations.

This program, conducted in conjunction with the WES program, is a company-wide community relations program that supports employees in partnerships with the cities and towns where they live and work. In each community, a team made up of local employees works with community leaders and organizations to understand local needs and to sponsor community projects, either with volunteer time, financial support, or both. Each community has an opportunity to work with the local team to help choose the projects that are the most important in its area.

Depth of Cover—Several sections in the Operating Manual address depth of cover. Page 6.13 of the Operating Manual describes backfilling procedures and requires a minimum fill of 12 inches. Section 2.15 of the Maintenance Crew OJT Program describes procedures for survey of shallow lines and defines a shallow line as less than 18 inches of cover. Maintenance Crew OJT Program describes procedures for lowering lines.

Markers—The Maintenance Crew OJT Program Skill Number 2.08 addresses pipeline marking requirements. The section describes permanent line markers; identifies special tools, equipment, and materials for marking; lists procedures for permanent markings; and discusses the installation of aerial markers used in air patrols. The Pipeline Marking Standard is referenced in the table of contents for the Operating Manual.

Pipeline warning markers are placed along the pipeline route to notify the public that a refined petroleum product pipeline is buried in the vicinity and to not dig before notifying Longhorn. The markers provide a toll-free telephone number to contact WES's Operations Control Center. The center is manned 24-hours per day, 365 days per year.

Right-of-Way Surveillance—The pipeline ROW is scheduled for weekly aerial and/or ground surveillance. The surveillance is used to evaluate the condition of the ROW and identify potential encroachments or pipeline exposures. If an emergency situation is identified, the aerial patrol would notify the area operations team so that appropriate action, based on the circumstances, can be taken. If the aerial patrol identifies any unauthorized construction activity on or near the pipeline ROW, the contractor would be notified that they are working near a refined products pipeline, to stop work, and contact Longhorn Operations Control Center.

One-Call—Longhorn will respond to One-Calls through the Texas One-Call system. The system provides a toll-free number for contractors and individuals to call prior to digging on or near the pipeline ROW. WES One-Call Services, Inc. (WilCall) provides One-Call ticket management and screening services for the Longhorn pipeline. Services include pipeline locating, excavation assistance, dispatching, record keeping, and auditing services. Longhorn operations personnel will locate and mark (i.e., flags, paint the ground) the exact location of the pipeline, and will be present when excavation occurs near or across the pipeline to ensure that construction activities do not endanger the pipeline.

5.2.6 Corrosion Control

Corrosion control procedures primarily involve maintaining the integrity of the pipeline coating and the CP system for the pipeline. The types of corrosion that must be prevented are external corrosion and internal corrosion. External conditions in the soil and atmosphere affect external corrosion. Internal corrosion is related to the products carried by the pipeline.

External Corrosion

Atmospheric corrosion—The slow rate of metal loss and the ability to inspect most steel exposures to the atmosphere create a low failure rate due to atmospheric corrosion. Experience however, indicates that certain 'hot spots' can facilitate accelerated corrosion. These hot spots include casings (where an alternate wet and dry environment, coupled with inability to inspect, is especially problematical), splash zones, insulation, and supports. Preventative measures most often employed are the application and maintenance of a protective paint coating.

Aboveground facilities, pipe in casings, and exposed or very-shallow pipe are susceptible to atmospheric corrosion. On sampling field inspections, conducted by DOT and its Contractor, it was noted that new construction generally had good paint coating or was soon to be painted (new station equipment). Some exposures were observed to have what appear to be inadequate coatings.

Buried Metal Corrosion—The potential for external corrosion for buried steel pipe depends on:

- Corrosivity of the soil;
- Condition of the coating, depending on:
  - Coating age;
  - Coating type; and
  - Visual inspections.
- Effectiveness of CP system, evidenced by:
  - Annual CP survey pipe-to-soil potentials;
  - CIS pipe-to-soil potentials; and
  - Internal Line Inspection (ILI) findings.
- Interferences potential, depending on:
  - Nearby utilities; and
  - Presence of casings.
- Potential for mechanical corrosion, depending on:
  - Pipe stress levels; and
  - Degree and timing of corrosion-specific inspections.
- ILI type; and
- ILI date.

Pipe Coating—Coating of aboveground metal surfaces is addressed in the Maintenance and Calibration Manual, MC-7.19, which references the recommended industry practice for coating piping as NACE RP0169-96—Control of External Corrosion on Underground or Submerged Metallic Piping Systems. The metal surfaces include valves, steel plate liners, tanks, mechanical couplings, metal connectors, valve boxes, and piping. Longhorn has a policy which requires all newly buried steel lines, including mainline, terminal, and station piping, to be coated. Coating selection requirements, handling requirements of coated pipe, and repair requirements of coated pipe are listed on pages 6.53 to 6.58 of the Operating Manual.

A more modern type of pipe coating is now being used. The fusion-bonded epoxy (FBE) coating, applied to newer portions of the line, has excellent corrosive prevention properties assuming it is properly applied. The original coal tar coating, applied on the older portions of the line, was a widely used design and has proven to have a long life span in many cases. Coatings are susceptible to age-related deterioration from mechanical abrasion and chemical reaction from absorption of gases and liquids. Evidence of the current coating condition is found through visual inspection reports, pipe-to-soil potential surveys, and detection of previous corrosion damages.

A description of Longhorn's CP system is included in the Maintenance and Calibration Manual on pages 7.15 to 7.18, and 49 CFR Part 195 requirements are listed on page 19.5 of the Operating Manual. DOT regulatory requirements for CP systems include testing of protected underground facilities once each calendar year, bimonthly testing of rectifiers, and testing of unprotected pipe once every five years. These requirements are addressed on pages 6.53 to 6.58 of the Operating Manual. Maintenance of CP equipment is addressed in the computer training module Computer-Based Training (CBT) Module #20. Locating rectifiers is addressed in the Maintenance Crew OJT Program manual skill number 2.25.

Coatings prevent water and/or soil from making direct contact with the pipe steel, thus eliminating the electrolytic path necessary for corrosion to occur. Precautions were taken in handling, bending, and backfilling the pipe to maintain the integrity of the coating. Coating for the newly constructed sections of pipe consist of FBE (14-16 mils). Lilly 2040 Topcoat was used where additional coating protection was necessary, such as crossings. Coatings on the refurbished 18-inch and 20-inch diameter pipeline consists of hot coal tar, asbestos felt, and glass fiber.

Cathodic Protection—Where the coating is damaged, disbonded, or otherwise compromised, the pipeline can experience external corrosion. To minimize this, CP is installed. CP is the application of direct-current electricity from an external source to oppose the discharge of corrosion current from anodic areas. When a CP system is properly installed, all portions of the protected structure (pipeline) collect current from the surrounding electrolyte (soil), and the entire exposed surface becomes cathodic. The original number and location of these systems is based on calculated demand for CP current. Additional systems are added as necessary to maintain adequate CP on the pipeline and associated facilities.

A CP system is in place for the refurbished 18-inch and 20-inch diameter pipeline. Temporary CP was applied to the newly constructed segments through bonds to other current sources. Permanent CP systems are currently being installed and will be completed in 1999.

Rectifiers and/or magnesium anodes are installed as necessary to provide CP current to the pipeline. Anode beds have a design life, become depleted over time, and must be replaced.

Depleted anode beds are detected by changes in CP readings and unacceptable readings. Part of the refurbishment of the System requires replacement of depleted anode beds. Thirteen new beds are being installed between the existing 50 beds from Galena Park to Crane. These recommendations are shown in Table 5-5. New anode bed designs for Longhorn in the Houston area use a CP current density of 0.12 milliamp (mA) per square feet (sq ft). The CP current density may suggest a poor coating. By contrast, design for a new coating system typically specifies about 0.001 to 0.01 mA per sq ft.

The effect of these factors on the corrosion potential at different locations along the pipeline is considered further in the relative risk assessment of Chapter 6.

Cathodic Protection Surveys—An important aspect of inspection and testing is the validation of CP. If the pipeline coating is perfect, there is no need for additional corrosion control, and CP would be unnecessary. However, coatings are never perfect initially and can be damaged from contact with rocks or equipment during installation or during operation. Coatings can also deteriorate over time. Indirect evidence (depleted anode beds) and experience suggest that some sections of inadequate coating are to be expected in the subject pipeline. CP provides an additional method of protection. The effectiveness of the CP system depends on the sufficiency of the voltage and current provided along the pipeline for buried sections. Periodic measurements of the CP voltage potential are required to verify the adequacy of the CP. Voltage readings between the pipe and a reference electrode are measured. Test leads or stations, installed at intervals of 1 to 2 miles along the pipeline, are used for semi-annual surveys and for “spot” testing throughout the year (Longhorn, 1999). These test stations consist of electrical wire connected to the pipe. Rectifiers, installed to provide the CP current, are inspected monthly.

CIS take voltage readings at intervals shorter than test lead intervals, and are taken from time-to-time, in selected areas. The CIS test interval used by WES is usually from 3 to 15 feet along the pipeline. Since corrosion problems can be localized, compared with station tests, CIS increases the opportunity for detecting potential problems.

CP has been mandated on interstate hazardous liquid pipelines since 1973. Current regulations require that the pipeline operator "...conduct tests ... to determine whether the protection is adequate" at least once each calendar year. DOT expects companies to follow “common industry practice,” which includes recommended practices of NACE.

Cathodic Protection Voltage Measurement Criteria—A generally accepted criterion for CP pipe-to-soil voltage readings, as measured by a copper-copper sulfate reference electrode, is at least –0.85 volts. A lower reading indicates decreased protection. For liquid pipelines, this value is used, based on its specification in DOT regulations for Natural Gas Pipelines (49 CFR Part 192), and is cited by NACE and elsewhere in the technical literature on corrosion control (NACE, 1996). The actual practice of ensuring adequate levels of CP is often more complex than this simple criterion. Readings must be carefully interpreted in light of the measurement system used.

There is controversy in the industry concerning appropriate methods to ensure adequate CP currents on all portions of the pipe. Readings can be taken with the impressed electric current supply to the system, provided from an alternating current/direct current (AC/DC) rectifier, turned either “on” or “instant off.” WES and EPC past practices both indicate that they use only a -0.85 volt “on” reading as the primary criterion. The IR drop subtracts the voltage drop through the soil from the reading to yield the “true value” of the pipe-to-reference electrode potential. If the IR drop is high, an “on” reading of -0.85 volts might actually be less negative than this, to a level considered inadequate to protect the pipe. Under certain conditions then, the pipe might not have adequate CP even when an “on” reading that is more negative than -0.85 volt is seen. The "instant off" reading might therefore better reflect the actual level of protective currents. However, there is no industry or regulatory agreement on the issue, and the -0.85 volt is usually considered a conservative criterion. (A safety margin is already included in the –0.85 volt value, for most soil conditions.)

In addition to deficient CP voltage, another problem is excess voltage. A voltage level that is too high electrolyzes water, resulting in hydrogen (H_2) liberation on any exposed pipeline metal. While corrosion does not occur, coating disbondment or H_2 blistering of steel can occur. WES uses –1.2 volts as a limit on pipe-to-soil voltage as a guideline.

The results of the 1998 CIS along the Longhorn pipeline would be used for several purposes. Areas of the existing pipeline between the Galena Park Station and Crane Station that require additional CP would be identified by the CIS, and CP system refinements would be implemented as necessary. The CIS results would be incorporated into the data that support Longhorn’s risk assessment process and the LIMS, allowing Longhorn to identify areas for operating maintenance and capital maintenance prioritization.

Internal Corrosion

Internal corrosion (IC) is the result of corrosive constituents in the products carried. The former EPC system carried crude oil. Compared with refined petroleum products, crude oil is generally more corrosive to the interior of a pipeline. The crude oil was more likely to cause IC than the future refined products.

Protection against IC is based on material of construction selection for the pipe and control of product specifications. Longhorn will control the threat of IC by:

- Corrosion inhibitor injection at Galena Park Station (injection rate of 0.75 pounds [lbs]/1000 bbl). Dosage will be adjusted to maintain an "A" rating on the NACE "rust test".
- Corrosion coupon tests, performed three times a year at El Paso terminal and Odessa station. The target corrosion rate will be less than 1 mil per year.
- Cleaning pigs are used twice a year to clean the line of debris and water and allow the corrosion inhibitor to establish a protective film on the pipe wall.
- Internal surface inspection for evidence of corrosion, whenever the pipe is removed from the system for any reason.
- Further investigation to determine the extent of the corrosion, followed by remedial actions, if necessary.

As with external corrosion, the inspection and test program is the final countermeasure.

Several sections of the Operating Manual address the control of IC. Chapter OP-15 of the Operating Manual discusses approved inhibitors, pump settings and dosage rates, precautionary measures for injection pumps, and sampling requirements for residual quantities of inhibitors at end terminals and metering stations. Internal examination of mainline corrosion coupons is addressed in OP-6.58. The Operator OJT Program manual includes Skill Number 5.29 for the removal of corrosion coupons and 5.31 for the sample of products. The Operating Manual, page 19.6, lists the generation of an ILI report, monthly inhibitor injection report, and a work order and damage report in response to the DOT regulations for internal corrosion control.

5.2.7 Leak Detection

The Supervisory Control and Data Acquisition (SCADA) system provides continuous monitoring of pump stations and block valve status. Leak detection is provided by field instrumentation and the SCADA system to enhance pressure and temperature compensated volume balance analysis between Galena Park Station, El Paso Terminal, and Odessa Meter Station. In addition, the Tulsa Operations Control Center performs a manually-calculated measurement line balance every two hours to provide a high level of leak detection. Significant leak prevention and detection plans are described in Table 5-6.

Larger leaks can be signaled by an alarm in the Tulsa Operations Control Center indicating that the pressure and/or flow rate has deviated outside of preset parameter limits. These limits are six percent and eight percent for flow rates and pressure, respectively (Williams, 1999). Thus, a decrease in flow greater than six percent from the target rate would cause an alarm at the Center within five seconds of the time the sensor detected the low flow rate. When a pressure or flow parameter alarm occurs, the controller reviews the pipeline operations and checks the line. If no cause is apparent, the controller will shut down the line. Mainline isolation valves will be closed and the line kept under pressure to determine its integrity and identify the location of any leak. The estimated time to detect, verify, and respond to the alarm is reported to be five minutes (Pearson, 1999).

The second method of detecting leaks is a manual mass balance calculation performed on the pumping and receiving meters. These balances are performed at the Tulsa Operations Control Center every two hours when the pipeline is operating at steady state. Discrepancies of ± 0.3 to 0.6 percent can be detected. When such a difference is noted, the accuracies of the meters in question are checked by remotely proving each one. If the meters prove to be accurate, a leak is suspected, and the line is shut down. The estimated time to prove the meters, verify the findings, and shut down the line is estimated to be 30 minutes to two hours.

Leak rates of less than 0.3 percent cannot be detected by current WES instrumental or mass balance means. Leaks of this level can only be detected by visual means or by detection at the leak location.

Table 5-7 summarizes of the detection time, response time, and the maximum amount of product that could be released during the time it takes to detect the possible leak and shut down the pipeline. Release volumes are provided for both the 72,000 bbl per day (bpd) and 225,000 bpd cases. The rates and volumes shown are based on the assumption that the leak rate is equivalent to the flow rate in the pipeline. Thus, the rates and volumes represent the maximums that would occur.

The Tulsa Operations Control Center is currently evaluating leak detection software that would allow the rapid detection of small leaks. One possibility is the implementation of a “Rate of Change” feature that already exists within the VECTOR software currently used with the SCADA system. Such a system would help detect small pressure changes that might be produced by relatively small leaks. Achievable detection levels with this system have not been defined. There is commercial leak detection software available that could be installed. UTSI International Corporation conducted a theoretical leak detection performance evaluation of the

Longhorn pipeline (Williams, 1999). They concluded that, with the installation of some additional instrumentation, potential leak detection performance could be significantly improved.

Further activities to which Longhorn has committed include work with local agencies to establish water quality criteria baselines at Barton Springs and Cold Springs and leak detection through weekly aerial patrols.

5.2.8 Surge Control and Overpressure Protection

Surge Pressure Analysis

Surge pressures are created when a moving fluid is suddenly brought to a halt. The kinetic (moving) energy is converted to potential energy, resulting in an increase in pressure and the creation of a pressure wave. In a fluid-filled pipeline, a positive pressure wave is propagated upstream of the point where the fluid flow is interrupted. Flow interruptions in a pipeline are usually due to valve closures or pump shutdowns.

A negative pressure wave travels downstream from the point of interruption. The pressure can decrease below the vapor pressure of the liquid, and some of the liquid can vaporize, forming vapor cavities. Each cavity may be large enough to separate the liquid into two segments. When the pressure in the system equalizes, the vapor cavity will collapse. The velocities of the liquid can be very high during these collapses, producing a significant pressure wave.

In 1998, Willbros Engineers, Inc. (Willbros) performed a surge pressure analysis of the Longhorn pipeline from Galena Park to El Paso (Willbros, 1999). The flow rates for the analysis were 115,000 bpd from Galena Park to El Paso, and 125,000 bpd from Galena Park to Crane. The lower flow rate was used because of hydraulic constraints in the section of pipeline.

Thirty-three cases were examined in the analysis. Most cases involved valve closures, with closure times ranging from 1.5 to 3.2 minutes. Four pump shutdown cases and one emergency system shutdown case were also examined. For the purposes of this study, the transported product was assumed to be No. 2 fuel oil. This fuel oil has the highest specific gravity of any liquids proposed for transportation in the pipeline. The fuel oil provided the most severe transient conditions in the analysis.

The 1999 analysis was conducted using the PSIM Version 1.04 computer program developed by Stoner & Associates, Inc. Willbros found that none of the case studies showed surge pressures that exceeded the maximum allowable surge pressure (MASP) levels previously determined. Several of the peak surge pressure levels were within 50 pounds per square inch gas (psig) of the calculated MASP, and surge pressure relief was recommended at a location upstream of the Satsuma Station. However, in the study, Willbros calculated the maximum operating pressure (MOP) using the pipe grade and wall thickness in accordance with ASME B31.4 code “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.” The MASP was calculated as 110 percent of the maximum operating pressure (MOP).

For most of the pipeline, the MOP calculated in this manner was above the MOP determined from hydrostatic testing and reported in the Longhorn Pipeline Project Description (Longhorn, 1999). Thus, the surge pressures determined in the analysis were compared to MASP levels that were inconsistent with the MASP levels defined from hydrostatic test results. Because of these inconsistencies, another surge pressure analysis was conducted by Willbros. The report was completed in early August 1999 (Willbros, 1999).

The SPS program Version 2.0, developed by Stoner & Associates, Inc., was used for the most recent surge analysis. Four cases were considered in the analysis:

- Galena Park to El Paso at a flow rate of 4850 bph (Case 1);
- Galena Park to Crane at a flow rate of 5000 bph (Case 2);
- Galena Park to El Paso at a flow rate of 8675 bph (Case 3 – ultimate flow rate); and
- Galena Park to Crane at a flow rate of 3225 bbl per hour (bph) (Case 4 – startup).

For Cases 1, 2, and 4, the effects of transient valve closures and pump shutdowns were determined for most of the remote control valves and pump stations along the pipeline. These locations are summarized in Table 5D-1 in Appendix 5D. At some locations, the 1998 surge analysis indicated that calculated surge pressures were significantly lower than the MASPs, and these cases were not repeated in the 1999 study.

Case 3 represents the hypothetical maximum flow rate at which the pipeline could operate. This flow rate is based on assumed locations for the additional pump stations needed to achieve the maximum flow. The actual pump station locations could be several miles from the currently assumed positions. The pump performances at the projected stations are also assumed. All of these variables will have a significant effect on the calculated surge pressures. Because of the level of uncertainty associated with Case 3, a surge analysis at the proposed maximum rate was not performed.

The results of the most recent surge analysis are summarized in Table B in Appendix 5D. Initially, the unmitigated surge pressures were determined and compared to the MASPs along the pipeline. The MOPs and MASPs were determined from Longhorn hydrostatic test data. As shown in Table B, the surge pressure exceeded the MASP limits for most of the modeled valve closures and pump shutdowns in the cases under consideration. The MASP exceedances occurred in four areas: near the Brazos River, near the Colorado River, near the Pedernales River, and upstream of Crane Station. The environmentally sensitive and hypersensitive areas relative to the areas of MASP exceedances are also indicated in Table B.

In the areas where MASP levels were exceeded, several measures were considered for reducing the surge pressure below the respective MASP limits. These methods are listed below:

- Install surge pressure relief systems at Satsuma, Warda, Cedar Valley, and Eckert stations;
- Interlock the inadvertent closure of a block valve with the shutdown of an upstream pump station;
- Change to slower valve closure times; and
- Qualify the affected sections of the pipeline for higher MOP and MASP by hydrostatic testing.

The surge analysis was repeated with one or more of the first three of the above mitigation measures being assumed for those events that had produced surge pressures above MASP levels. As shown in Table B, one or more of the proposed mitigation measures produced surge pressures that were below the MASP for all the events and locations included in the analysis. The surge pressures were only slightly below the MASP for several of the events.

At the conclusion of the surge analysis, a solution to eliminate the overpressure conditions was recommended. After considering the potential mitigation measures, the recommended solution was to hydrostatically test the affected segments of the pipeline to a higher pressure. According to the surge analysis report, the existing MOP levels for the existing system are approximately 30 to 160 psig lower than those allowed by ASME B31.4 and CFR Part 195. By successfully hydrostatic testing approximately 85 miles of pipeline to a higher pressure, the MOP and MASP levels will be raised above the surge pressure in the four line segments of concern. This alternative would eliminate the need for surge pressure relief systems and valve interlock systems and would eliminate the operational risks associated with these systems.

Since the recommended hydrostatic testing has not yet been performed, the MOP and MASP levels in the areas of concern are not defined. In the current absence of these new levels, some means of evaluating the potential for overpressuring the pipeline was needed for the relative risk assessment model. A worst-case scenario was developed for the Longhorn pipeline to determine if surge pressures exceeded MOPs at any point along the line. The basis of this scenario was the hydrostatic pressure profile determined for both high and low flow rates. This pressure profile incorporates head loss due to friction using the Hazen-Williams equation as well as the pressure changes due to differing elevations. The highest-pressure condition, No. 2 fuel oil being transported at 7300 bph, was used in the surge analysis.

Assuming instantaneous valve closure, a maximum pressure increase was determined using the formulas by Muhlbauer (1996). It was assumed that the increase in pressure was transmitted along the entire upstream segment of the pipeline without any dissipation of pressure due to pipe expansion or friction loss. The maximum surge pressure created at the above mentioned flow rate was added to the hydrostatic pressure for each point on the line to determine where the highest pressures occur. This is a significant simplification of actual operating conditions. Since an instantaneous stoppage of flow would not occur under normal operating circumstances, the actual surge pressures generated in the pipeline would likely be less than those calculated by this approximation.

The results were grouped in five classes based on the percentage of MOP. Calculated surge pressures ranged from 80 percent to 181 percent of MOP. Pressures greater than 130 percent of MOP were given the lowest score, while any pressure under 100 percent of MOP was given the highest score. These scores were used in the pipeline relative risk model.

5.2.9 Fatigue Monitoring

Fatigue monitoring uses data on pressure fluctuations of the pipeline system to estimate the potential for crack growth in the pipeline. There is no regulatory requirement for fatigue monitoring. Some pipeline operators have implemented formal fatigue monitoring programs which consist of collecting line pressure data from the SCADA system and analyzing trends. This analysis includes using mathematical methods for predicting potential crack growth and determining the remaining fatigue life of the system. Longhorn does not have a formal fatigue monitoring program in place for this pipeline. Longhorn is considering such a program which is consistent with recommendations from Kiefner and Associates (Johnston, 1999).

5.2.10 Exposed Pipe Control

There are two types of exposed pipe. The first is pipe exposed to the atmosphere by design. The second type of exposed pipe is previously buried pipe that has been exposed because of soil erosion and wash outs. Several sections of the operating manuals address the inspection of exposed piping. The inspection of exposed piping at crossings includes visual inspection of the outer surface of the pipe for overall condition, pipe coating, pipe contacts to supports and the supports, and record keeping. For buried piping exposed to atmosphere, the inspection identifies the condition of coating and evidence of corrosion, surface pipe pitting or leakage, and corrective and remedial actions. Lowering of exposed lines includes pre-checks and lowering procedures.

Currently exposed pipe is being evaluated in the context of relative risk assessment rankings as described in Chapter 6, to determine where such pipe requires re-burial or other corrective actions.

5.2.11 Crossings

Waterway crossings are regulated by 49 CFR §195.412(b) which requires that crossings under navigable waterways be inspected once every five years to determine the condition of crossings. Several sections of the Operating Manual address water crossing inspections, including OP-19.5 which states the DOT requirements, OP-6.48 to 6.51, and Maintenance Crew OJT 2.06. Inspections include re-establishing base lines on plan drawings, locating pipe, re-establishing reference points and benchmarks, inspecting exposed pipe, and reporting surveys and inspections.

5.2.12 Right-of-Way Maintenance

Longhorn uses both aerial patrol and ground patrols to meet the regulations. ROW issues addressed in the manuals include methods of patrol, patrol intervals, patrol routines, general patrol procedures, patrol observation items, reports and forms, and emergency reports. Procedures are listed for clearing and maintaining the ROW and for investigating third party damage to the pipeline, including documentation with photographs and site drawings and third party statements.

5.2.13 Staffing

Longhorn plans to locate field staff to cover the entire route of the System and at the El Paso Terminal. The pipeline system and terminal would be supported through area operating teams consisting of: field technicians, corrosion technicians, maintenance coordinators, PSM specialists, field tech supervisors, field office administrators, and area managers. These teams would be supported by a centralized technical services team that include engineering, environmental, health and safety, DOT regulatory compliance, training, corrosion and risk mitigation, operations control, design, and real estate services.

5.2.14 Training

Longhorn has established and conducts a continual training program to instruct operating and maintenance personnel as well as support personnel in engineering, safety and environmental protection. Annual training is reviewed to assure its effectiveness. Training reviews are documented on various forms including the Employee Performance Review form, Training Enrollment, Training Class Attendance, OJT qualification checklist, and automatically in the CBT documentation program.

Longhorn's Operations Training Program consists of the following major components:

- New employee orientation;
- OJT;
- CBT;
- In-house hands-on and vendor training schools/seminars;
- Technical training;
- Safety meeting training program;
- Supervisor training; and
- System of operating manuals.

The new employee is introduced to overall company policies and procedures through the New Employee Orientation. Emphasis is placed on personal and facility safety. Following the New Employee Orientation, new employees are trained with OJT Procedures and CBT Program modules. OJT manuals provide information regarding specific job tasks at the facility. Manuals have been developed for both station operators and maintenance crew operators. One week of field training is required for new hires who have not previously had field experience. Qualification checklists track job relevant skills and assess the training and development of the operator. Guidelines and requirements are mandated for the first 180 days of employment for new employees.

In OJT, workers are evaluated for their current knowledge of the subject material. Skills are discussed and illustrated with an open forum format for questions. Key points are also covered. Workers would be checked for understanding and performance of the skill set. Checklists are maintained for each worker. The checklists cover required modules with sign offs for dates of demonstrated competency. The checklists also allow for critical checks of core knowledge in the event that the worker needs additional training on key concepts. Hazard assessments and selection of personal protective equipment selection skills are reviewed annually.

The CBT Program includes 44 modules. These modules are designed to teach the fundamental concepts and principles of pipeline operations. Certain modules are designated for the training of newly hired field and operating employees. There are additional requirements for temporary and summer employees. A total of 19 modules are designated for the training of newly hired operators. These modules are required to be completed within the first 120 days of employment. Computer-based modules track the training of employees in the computer modules with quizzes at the end of the lessons. Supervisors may request that an employee re-take a module if the supervisor determines that the employee's knowledge in the area is weak.

Other operator and employee training includes field refresher training with nine computer modules on field safety training. Portions of the refresher training are required on an annual, biannual, and triannual basis. The in-house/vendor training is a program for providing expert information on specialized training of specific operations or equipment through outside vendor consultants or in-house experts. The Safety Training Program provides training for all operating employees for safe performance of all designated job responsibilities. The Supervisor Training Program develops and maintains effective field supervisors capable of managing the day-to-day operation of the facilities.

5.2.15 Tank Maintenance Inspection

All tanks and related equipment have been constructed in accordance with industry standard API 650 — Welded Steel Tanks for Oil Storage; API 651 – Cathodic Protection of Aboveground Petroleum Storage Tanks; API 2000 – Venting Atmospheric and Low Pressure Storage Tanks; API 2003 – Protection Against Ignitions Arising Out of Static, Lightning, and

Stray Currents; API 2350 – Overfill Protection for Storage Tanks in Petroleum Facilities; and National Fire Protection Association (NFPA) 30 – Flammable and Combustible Liquids Code.

The main purpose of the Tank Maintenance Inspection Program is to inspect all tanks in accordance with API 653 inspection requirements, and make recommendations on necessary repairs to ensure the integrity of the tanks. Under new DOT tank rules, an annual inspection is required. The following paragraphs describe some of the components of the Tank Maintenance Program.

All of the pump stations are equipped with 1000-gallon sump tanks. Product from equipment drains, scraper (pig) launcher and receiver pads, and thermal relief valves is collected in these tanks. A sump pump is installed at each station to periodically pump the collected product back to the mainline.

In addition to swap and storage tanks, Crane Station also includes a 1500-bbl pressure relief tank. A low-pressure relief system relieves into this tank to protect the American National Standards Institute (ANSI) 150-per square inch (psi) piping on the tank manifold from the mainline pressure. The relief tank is sized to contain a volume equivalent to 10 minutes of flow at the maximum mainline flow rate. A relief tank is also provided at Satsuma Station. There are 19 tanks located at the El Paso Terminal.

All product storage tanks have been constructed in accordance with industry API standards as a minimum requirement. All tanks are designed with a single steel bottom, with leak detection in the form of an underlying geosynthetic clay liner. Small pipes are installed between the steel tank bottom and the impervious geosynthetic liner to allow periodic inspections for early indications of tank-bottom failure.

All storage tanks are located within diked areas. At the El Paso Terminal, the areas around each tank inside the dikes are surfaces with compacted, liquid-tight crushed shale. Each dike is sized to contain 110 percent of the largest volume of liquid that can be released from the largest tank within the diked area. This requirement exceeds NFPA 30 requirements. Drainage inside the dikes is designed to divert liquid away from the tanks.

External or In-Service Inspections

All tanks are given a visual external inspection by an inspector certified in API 653. This inspection is conducted at least every five years or at the quarter corrosion rate life of the shell, whichever is less. The inspection includes a survey of the tank for settlement activity, measurement of the shell thickness for corrosion, inspection of vents, inspection for tank shell damage, seal gap measurements, floating roof inspection, fixed roof inspection, etc. The inspection is performed by a certified inspector according to API 653 and documented on an In-Service Inspection form. The forms are retained in the records of the Tank Maintenance Department.

Internal or Out-of-Service Inspection

All tanks are given a formal internal inspection to ensure the integrity of the tank bottom. This inspection is initially conducted after ten years of operation. Subsequent inspections are established in accordance with API 653, but do not exceed twenty-year intervals. The inspection is performed by inspectors certified pursuant to API 653 and documented on an Out-of-Service Inspection form. A copy of the inspections is retained in the Tank Maintenance Department's records.

5.3 PIPELINE PHYSICAL EVALUATION

The preceding section discussed operational procedures that will be applied to the System. As discussed in Chapter 3, refurbishment and modifications have been made since Longhorn's acquisition of the System from EPC in October 1997. The present and future condition of the System, as it will be under Longhorn's operation, is influenced by past EPC practices, both in the original construction and as operated and maintained. This section examines the attributes and conditions of the System based on data and information available to this study. These attributes and conditions are relevant for assessing relative and absolute risks in Chapter 6, and impacts analyzed in Chapter 7. Attributes such as age, type of pipe, results of inspections and tests, in combination with procedures and mitigation measures, influence the integrity of the System.

5.3.1 General Attributes

The Longhorn pipeline consists of various segments installed at different times, as described in Chapter 3. Most of the line (91 percent) between Kemper Station near Crane, and Satsuma Station in Houston, was built in 1950. Small sections were replaced as needed over the years. The 18-inch pipeline connecting Crane to El Paso was built in 1998, as was the 8-inch lateral from Crane to Odessa. A 9.1-mile section of 20-inch pipeline between Galena Park and Satsuma was replaced in 1999.

The age of major sections of the pipeline, between Galena Park and the former Kemper Station, near Crane, is summarized in Table 5-8. A listing showing basic pipe characteristics is provided in Table 5-9. The age of the pipeline is a factor in the integrity evaluation because of the potential for age-related deterioration if the pipeline were not adequately maintained, and because of the potential effects of changes in manufacturing and construction specifications over time. The direct effects of age on physical condition and pipe properties from manufacture are discussed later.

Specifications in effect at the time of construction were used for all pipe. Specifications for the 1950 pipe were obtained from the bid package of Humble Oil in October 1949. Specifications in the new sections of the System are from WES documents from 1993 (Williams, 1993). These WES specifications apply to any new construction.

An overview of construction specifications is provided in Table 5-10. In general, the 1993 specifications are more stringent and more detailed than the 1949 specifications. Some key differences are:

- The level of detail of the pipeline material specifications has increased.
- Minimum depth of cover and vertical clearance requirements has increased and new requirements have been added (for example, at road crossings).
- Major river crossings now require major bank reinforcement (rock plugs, rip-rap) and prior hydrostatic testing of the crossing section of the pipe.
- Coating type has changed from coal tar enamel to FBE for new construction;
- Welding requirements and techniques have changed.
- Hydrostatic testing pressure requirements have increased 55 percent, and test duration has doubled.
- No CP was required in 1949; it is specified in detail in 1993. It is unclear when CP was installed on the pipeline.

Longhorn procedures call for new segments of the System to be designed, constructed, or qualified, inspected, and tested to the latest DOT regulations and industry standards, ASME B31.4, API 1104, and OSHA. Similar construction techniques and specifications would be used for any future construction. A limited amount of new construction is required to complete the proposed EA project. The El Paso laterals are scheduled to be constructed pending the EA decision in 1999.

Figures 5-1 through 5-3 show the operating pressures, MOPs, and minimum hydrostatic test pressures for No. 2 Fuel Oil at 72,000 bpd, 125,000 bpd, and 225,000 bpd, respectively. Figures 5-4 through 5-6 show the same information for gasoline. The purpose of these figures is to show the normal variation in operating pressures reflecting pressure drop and elevation changes along the pipeline route and how the planned local operating pressures compare with both the MOP and the hydrostatic test pressures. The latter were used to qualify the pipe for the specified MOP.

5.3.2 Effects of Age

Age alone is not a reliable indicator of pipeline risk as some pipelines have been in good operating condition for more than 50 years (Muhlbauer, 1992). However, concerns regarding the age of the older pipe have been raised with respect to the System. Several ways that the age of a pipeline can influence the potential for failures are through corrosion, fatigue, and manufacturing and construction methods. Age effects can be countered by appropriate mitigation measures.

Corrosion

There are no identified metallurgical changes in pipe materials that have been buried for years under impressed electrical currents, as from a CP system. Experts believe that there is no effect of age on the microcrystallne structure of steel such that the strength and ductility properties of the pipe are affected. The primary metal-related phenomenon is the potential initiation and propagation of cracks from fatigue stresses, primarily driven by varying temperature and fluctuating pressures over time. Corrosion is the other time-related threat, as is the threat of undetected outside force damage.

Corrosion is time dependent and related to the environmental conditions of the pipe. It is reasonable to assume, therefore, that with increasing passage of time, the opportunity for undetected (and hence, uncontrolled) corrosion and/or fatigue effects increases. The coating system is susceptible to age-related deterioration from mechanical abrasion and chemical reaction from absorption of gases and liquids. That is why the corrosion control program, already discussed, is in place.

Fatigue

Fatigue results in crack formation and propagation, which if unchecked, can lead to pipe failure. Pressure fluctuations during pipeline operation over long periods of time can lead to fatigue. Hydrostatic testing, fatigue monitoring, and ILI with crack detection tools, are the three primary means by which fatigue problems are identified so that appropriate remedial actions can be taken.

Manufacturing and Construction Methods

It is commonly accepted that manufacturing methods employed during the forming of pipe for the older portions of the Longhorn pipeline did not match today's standards. Specifically, low frequency Electric Resistance Weld (ERW) and/or Electric Flash Weld (EFW) pipe forming processes (used extensively prior to 1970) have been identified as being more susceptible to seam failures. Failure mechanisms identified for low-frequency ERW and EFW pipe are:

- Lack of fusion;
- Hook cracks;
- Nonmetallic inclusions;
- Misalignment;
- Excessive trim;
- Fatigue/corrosion fatigue;
- Selective corrosion (crevice corrosion);
- Hard spots; and
- Fatigue at lamination/ERW interface.

These mechanisms, failure databases, and supporting metallurgical investigations are more fully described in technical literature references (DOT, 1989; Fields, 1989). Since 1970, the use of high-frequency ERW techniques, coupled with improved inspection and testing techniques, has resulted in a more reliable pipe product.

The older pipe in the System, remaining from the EPC line, was welded using low frequency ERW and EFW. It is therefore likely that the type of pipe found in the older sections of the Longhorn pipeline is more susceptible to seam failures than pipe that was manufactured with more modern techniques. Kiefner and Associates suggest that this pipe might be more prone to seam failure but has been adequately addressed through recommendations in their report, (Johnston, 1999). The pipe grade specified for the older pipeline was to have strengths of 45,000 psi to 52,000 psi in the transverse direction and at least 42,000 psi in the longitudinal direction. This does not appear to be unusual for both strength and ductility for pipe manufactured at that time.

Hydrogen blistering at laminations was a reported cause of failure in two of the three hydrostatic test failures in 1995. This implies the presence of laminations and an aggravating presence of hydrogen, perhaps from sour crude oil service (Johnston, 1999).

Similar to the discussion on pipe manufacturing techniques, the methods for welding pipe joints have improved over the years. Girth welds today must pass a more stringent inspection than welds from the original construction of the line. Welding standards such as API 1104 (incorporated by reference into 49 CFR Part 195) specify more and different potential weld defects to be repaired than standards from 1950. However, some welding specifications and options for welder tests were a part of the original Humble Oil Company construction specifications for the subject line.

It is not certain that girth weld defects, as defined by today's welding inspection standards, increase the probability of weld failure in an inspected and tested pipeline. However, this issue illustrates an improving safety and risk-awareness evolution over time, presumably rooted in actual experience and supported by engineering calculations. In addition to the tightening specifications, there is leak history evidence that there might be a greater chance for girth weld failure in the older line sections.

A concern investigated is the potential existence of non-steel components in the older portions of the line. Specifically, the possible use of cast-iron type materials, weaker than steel, and unsatisfactory for this service, was investigated. Valves and pumps were refurbished by a national contractor specializing in such activities for the pipeline industry. According to Longhorn, if the valves or pumps were not steel, this would have been brought to WES's attention in the refurbishment records of the contractor. Observations in the field showed that valves at the Cedar Valley Station, as an example, carried the ANSI 600 lb rating. That pressure rating corresponds to an operating pressure of 1440 psi, consistent with the pipeline MOP range.

Countering Age Effects

Potential effects of age are countered through the maintenance program for identifying flaws in coatings, providing adequate CP, ILI, and hydrostatic testing. If the potential age-related effects are properly controlled, the design life of the steel is considered indefinite.

5.3.3 Pipeline Inspection and Testing

Inspection and testing is fundamental to pipeline integrity. The purpose of inspection and testing is to validate the structural integrity of the pipeline and its ability to sustain the operating pressures. The goal is to test and inspect the pipeline system at frequent enough intervals to ensure pipeline integrity. This section focuses on inspections and tests that have been done and includes a review of past practices and data.

Inspections and testing methods consist of those mandated by regulations as well as those that are independently initiated by the operator. Methods of inspection and testing are listed in Table 5-11.

Pipeline integrity is ensured by two main efforts: 1) the detection and removal of any integrity threatening anomalies to ensure the current pipe integrity; and 2) the avoidance of future threats to the integrity. A defect is considered to be any undesirable pipe anomaly, such as a crack, dent, or metal loss, which could lead to a leak or spill during operations, if it is sufficiently severe. Possible defects include seam weaknesses associated with low-frequency ERW and EFW pipe, dents/gouges from past excavation damage or other external forces, external corrosion wall loss, internal corrosion wall loss, laminations, pipe body cracks, circumferential weld defects and hard spots.

The absence of any of the above defects of sufficient size to compromise the integrity of the pipeline is proven through hydrostatic testing and ILI, the two most comprehensive integrity validation techniques used in the industry today. CP counteracts soil conditions conducive to external corrosion, in the presence of coating inadequacies, and its potential effectiveness is determined through CP voltage surveys along the length of the pipeline. All of these measurement-based inspections and tests are occasionally supported by visual inspections of the system. Each of these components of inspection and testing of the pipeline are discussed further.

Hydrostatic Testing

Hydrostatic testing is used to confirm the ability of the pipeline to sustain its specified operating pressure and establish a corresponding MOP. The testing is beneficial in countering age effects by removing critical defects. Hydrostatic testing to a level significantly higher than operating pressure (usually 1.25 times MOP) adds a margin of safety for future potential pipe weakening through corrosion, fatigue, or outside damage. This margin allows the line to operate safely at the specified operating pressure.

The safety margin provided by the hydrostatic test may decrease over time because the test only verifies the pipe integrity at the time of the test. The probability of defect growth and addition since the test date must be considered. Since a new defect could be introduced at any time or defect growth could accelerate in a very localized region, the test usefulness is tied to other operational aspects of the pipeline. Introduction of new defects could come from a variety of sources, such as third party activities or corrosion. For this reason, hydrostatic test data have a finite lifetime as a measure of pipeline integrity without other supporting evidence such as proof of continuing cathodic protection, ILI, and fatigue analysis. Hydrostatic testing is one component, along with these others, of a sound integrity management program.

Hydrostatic testing is a DOT regulatory requirement for new construction and replacement pipe. There is not a re-test requirement. Hydrostatic test data apply at the time they were taken, but conditions of the pipe could change; therefore, technical literature suggests a means for estimating re-test intervals if an operator were to conduct periodic testing as a risk control measure (Johnston, 1996).

A hydrostatic re-test conducted on the EPC system in 1995, with the associated defect repairs and removals, provides some evidence of past pipe integrity. A summary of hydrostatic tests performed on the EPC pipeline system is presented in Table 5-12. The table shows the segments involved, by stationing and the test pressures used and the results in terms of where failures occurred. These failed sections of pipe have been repaired or replaced. In addition to tests on the EPC system, hydrostatic tests are being performed on new pipeline sections installed from Galena Park to Valve J1, Crane to El Paso, and Crane to Odessa, when construction is completed.

External corrosion could have occurred during the period from 1995 to the present in areas where coating damage or CP voltage was inadequate. Corrosion control measures were applied during the period since the last test in 1995. This is discussed further in the section on CP history. Fatigue-induced defect growth from pressure fluctuations should not have occurred since the line was not in operation since the hydrostatic test. Any non-service-related fatigue loadings (such as traffic over roadway crossings) are of such minor magnitude, they are not typically considered to contribute significantly to fatigue stresses for crossings that are cased or have adequate depth of burial.

Any defects, such as cracks and corrosion, of a size and configuration that would cause the pipe to fail under the pressures applied, would have been detected during the hydrostatic test. Defects of a size and configuration smaller than these that survived the hydrostatic test, would not be expected to fail under normal operating pressures, since the test pressure was 25 percent higher than the MOP for each line segment tested.

Internal Line Inspection

ILI, also called “smart pigging” or “intelligent pigging,” is the use of an electronically-instrumented device, travelling inside the pipeline, that measures characteristics of a pipe wall. The industry began to use these tools in the 1980s. The pipe conditions found which require further inspection are referred to as anomalies. General and detailed discussions of these tools are available in the technical literature (Muhlbauer, 1996; Conference Proceedings, 1998). The use of ILI as an inspection device is not a regulatory requirement. However, in recognition of the value of these devices and their growing use in the pipeline industry, DOT regulations require that all new pipe installations be designed to accommodate ILI devices. The line diameter, fittings, valves, and other parts of the line must therefore be able to accommodate the passage of these devices.

The state-of-the-art for ILI has advanced to the point that many pipeline companies are basing extensive integrity management programs around such inspection. A wealth of information is expected from such inspections when a high quality, in-line device is used and supported by knowledgeable data analysis. It is widely believed that pipe anomalies can be detected through ILI which are of a size that would not be detected through failure under a normal hydrostatic test. However, anomaly detection is not 100 percent accurate even with the most advanced techniques. Uncertainty regarding true system strength will remain even after inspection, and similar to the hydrostatic test, ILI test results are strictly valid for a finite time period.

General types of anomalies that can be detected by ILI include:

- Geometric anomalies (dents, wrinkles, out-of-round pipe);
- Metal loss (gouging and general, pitting, and channeling corrosion); and
- Cracks or crack-like features [fatigue, stress corrosion cracking (SCC), sulfide SCC, laminations, hydrogen-induced cracking (HIC), and stress oriented HIC].

Some examples of available ILI devices are: caliper tools, magnetic flux leakage (MFL) low and high resolution tools, ultrasonic wall thickness tools, ultrasonic crack detection tools, and elastic wave crack detection tools. Each of these tools has specific applications. Caliper tools are used to locate pipe deformations such as dents or out-of-round areas. Either can indicate previous third party damage or impacts of other outside forces. MFL tools identify areas of metal loss with the size of the detectable area depending on the degree of resolution of the tool. Ultrasonic wall thickness tools detect general wall thinning. Crack tools detect cracks, as opposed to metal loss. Currently, no single tool can detect all types of anomalies. Not all ILI technologies are available for smaller line sizes. The Longhorn pipeline consists of 18- and 20-inch diameters and is large enough to accommodate most tools—the 8-inch line to Odessa might have limitations.

Depending on vendor specifications and ILI tool type, detection thresholds can vary. The degree of resolution also depends on anomaly size, shape and orientation in the pipe. The probability of detecting an anomaly using ILI increases with increasing anomaly size. Smaller anomalies as well as certain anomaly shapes and orientations have lower detection thresholds than others. Vendors report detection thresholds for general corrosion, with detection capabilities up to anomaly diameters greater than the pipe wall thickness and depths greater than 5 to10 percent of the wall thickness. Detection thresholds for pitting corrosion are in the range of 10 to 40 percent of the wall thickness and anomaly characterization accuracy is ±10 percent of wall thickness for corrosion depth (Conference Proceedings, 1998).

The pipe wall thickness is designed to safely accommodate the expected operating stresses, including normal operating pressure, surge pressure, external forces (e.g., traffic loadings), the weight of the pipe itself, and other factors. Any abrupt changes in wall thickness or shape can amplify the stress level in the pipe wall, potentially resulting in failure. Therefore, the ILI detection of anomalies, which reduce the wall thickness or which have the potential to amplify the stress level in the wall, is an important preventative measure.

After receiving an ILI indication of an anomaly, an excavation is often required to more accurately inspect the pipe and make repairs. Excavating to inspect the pipe is also used to validate the ILI results. The process of selecting appropriate excavation sites from the ILI results can be challenging. The most severe anomalies are obviously inspected, but depending on the resolution of the ILI tool and the skills of the data analyst, significant uncertainty surrounds a range of anomalies, which may or may not be serious. Some inaccuracies also exist in current ILI technology such as with pig distance measuring, having reference points too far from the anomaly, and errors in pig data interpretation. These inaccuracies make locating anomalies problematic.

Probability calculations can be performed to predict anomaly size survivability based on ILI tool detection capabilities, measurement accuracy, and follow-up validation inspections. These, combined with loading conditions and material science concepts, would theoretically allow a probabilistic analysis of future failure rates. Such calculations are dependent upon many assumptions and are not fully developed under the current scope of this analysis.

Several industry-accepted methods exist for determining corrosion-flaw severity and for evaluating the remaining strength in corroded pipe. ASME B31G, ASME B31G Modified, and RSTRENG are examples. Several proprietary calculation methodologies are also used by pipeline companies. The contractor hired by Longhorn pipeline to evaluate the 1995 ILI data reportedly used a variation called CORRCALC. CORRCALC estimates the MOP for the pipe based on anomaly characteristics, using the ASME B31G method. These calculation routines require measurements of the depth, geometry, and configuration of corroded areas. Depending upon the depths and proximity to one another, some areas will have sufficient remaining strength despite the corrosion damage. The calculation determines whether the area must be repaired.

EPC performed an ultrasonic ILI in 1991 and the data were deemed to be inconclusive, according to testimony received. Smart pigging on this pipeline was next carried out in 1995, prior to Longhorn's acquisition of the system in 1997. The EPC pipeline from Satsuma to Crane (current station location) was examined with a geometry pig and low-resolution MFL internal inspection device. Five dents, identified by the ILIs, were recommended for repair. The data analysis identified approximately 187 anomaly locations recommended for direct inspection. The results of the excavated inspections (dig-outs) are summarized in Tables 5-13 and 5-14. Table 5-13 shows the sections inspected, the types of anomalies found, and the pipe length with anomalies. Table 5-14 shows the anomaly count.

The inspection had a resolution that would detect anomalies in excess of 25 percent of the pipe wall thickness in depth. Cracks, laminations, pits of certain depths, and some anomaly configurations might not have been reliably detected by this inspection.

As with hydrostatic testing, ILI results are applicable for a finite time period. It is reasonable to assume that the opportunity for operational-related anomaly growth was limited or non-existent because the line was not in operation since the 1995 inspection. Since a new anomaly could occur following the inspection or localized anomaly growth rates could change, operational aspects of the system, such as third-party damage prevention and corrosion control, are important between ILI. Longhorn has committed to additional ILI as presented in Chapter 9.

Cathodic Protection History

One issue for this pipeline is the reliability of the CP system when EPC operated the line, especially between the EPC shutdown and Longhorn's acquisition of the line. The contractual agreement between Longhorn and EPC stipulated that EPC would maintain the system. A copy of that contract was obtained and verified. Rectifier inspections and CP surveys taken during the interim period were also examined. There is indication from the ILI results that shows corrosion anomalies, and from CP records that there might have been some gaps in CP. Also, several other sources of data yield information regarding corrosion control effectiveness for the subject line. For instance, test lead readings from 1992 to 1998 were examined, as were CIS surveys from 1994 and 1998.

In the event of low CP potentials, less negative than -.085 volt, a "-100 millivolt (-0.10 volt) shift" criterion can be applied to determine if the pipe is adequately protected. The low readings in some cases might indicate problems in coating condition or other deficiencies in the corrosion prevention systems. Note that since CP is used in conjunction with coating, the coating would also have to be defective, and soil moisture and electrolyte conditions would have to be such that the rate of corrosion during the interrupted period would lead to a problem. Low readings do not necessarily mean that corrosion has occurred to a significant extent.

Station test lead results for the EPC/Longhorn line are summarized in Table 5-15. CIS data were available from 1994 and 1998. Results of the 1998 survey are summarized in Table 5-16. The CIS survey in 1998 used an "on" reading from Galena Park to Crane, with the exception of two sections where instant "off" was used. One, about 21 miles long, begins west of Cedar Valley Station and extends across the Pedernales River. The other is about 12.5 miles long, and is located just east of Big Lake Station. While this is consistent with the CP criteria used by WES, the lack of an "instant off" reading over most of the pipeline limits the ability to find special situations or to fully diagnose problem areas.

Visual Inspections

Visual inspections are required by regulations whenever a buried pipe is exposed, and, as a matter of course, for other parts of the System that are normally observable. Routine inspections of the System as a whole are covered in the section on ground patrols and aerial surveillance. This section is restricted to a discussion of coating inspection and inspection of pipe that is exposed.

A file of inspection and repair reports from 1972 to 1996 was compiled and reviewed for identifications of coating condition. The inspection data from EPC for the last ten years are found in Table 5-17. The data comprises approximately 425 reports:

- 1970s: 28 reports;
- 1980s: 263 reports; and
- 1990s: 134 reports.

The coating was noted in the reports as follows:

- Good: 274 observations;
- Fair: 91 observations; and
- Poor or bad: 32 observations.

Longhorn intends to repair any areas of inadequate coatings.

Visual inspection of the internal surface of the pipe is typically conducted when the pipeline is cut, excavated, and/or removed during pipeline replacement or repair activities.

DOT Site Inspections

In addition to inspections already conducted or being conducted by the company, in March through May 1999, visual inspections and some tests were carried out under the direction of DOT along certain portions of the pipeline covering the entire route. Several separate site visits to the line were made. These visits were general walk-through inspections to observe the condition of the ROW and to observe crossings, exposed pipe areas, and proximity to sensitive receptors. A second series of visits were carried out to closer examine conditions in selected areas. In this later inspection/test series, DOT supervised random measurements of CP potentials and operation of block valves.

Ground Patrols and Aerial Surveillance

Regular patrols are used to prevent and detect damage to the System. The visual inspection of the ROW is intended to detect evidence of a leak such as vapors, unusual dead vegetation, bubbles from submerged pipelines and sheens on water. Threats include excavating equipment operating nearby, new construction of buildings or roads, or any other activity that could cause a pipeline to be struck, exposed, or otherwise damaged. Evidence of past activity is usually present for several days after the activity and may warrant inspection of the pipeline. The effectiveness of the aerial surveillance depends on several factors such as frequency, surface vs. air patrol, speed, altitude, training of spotter, and other variables impacting response to discoveries.

5.3.4 Depth of Cover and Exposed Pipe

Cover over the pipeline offers some protection from external hazards such as being struck by excavating equipment; the deeper the pipe, the less likely it will be hit by an excavator. In some areas, such as overpass stream crossings, the pipe is deliberately aboveground. Unintended exposures occur from time to time, primarily from ground erosion and stream scouring. Depth of cover can also vary with location. For buried pipe, 49 CFR Part 195 requires certain minimum depths of cover for new construction. For existing pipe, depth of cover and exposure are issues from an integrity standpoint with regard to protection from third party damage and potential atmospheric corrosion. Therefore, the depth of cover for buried sections and conditions of exposed pipe were examined, as discussed below.

Depth of Cover

Depth of cover surveys have been conducted by remote sensing and probing. The most recent survey was completed in April, 1999. Figure 5-7 shows a profile for the length of the pipeline and indicates that depth of cover varies. These depth of cover results have been generated from a pipeline database developed for this project. Between Kemper and Satsuma, the probed depth is shallower in the western region and deeper in the east. This can be explained by the nature of the subsurface terrain, which is hard and rocky in the west and softer in the east. As discussed earlier, the 1949 construction specifications called for a minimum 24 inches of cover in soft terrain and 12 inches in rocky terrain. The survey shows a cluster of about 18 inches in the west. As an example of the profile with a greater degree of resolution in a local area, Figure 5-8 shows the depth of cover profile across a shorter section of the route covering the Edwards Aquifer zone, a section which also includes the high population zones in the Austin area, from the Colorado River to Cedar Valley Station. The full survey data are given in the cited reference, which is retained in the project supporting documents file.

In the refurbishment of this system, various areas were selected for remediation of depth of cover. At this time WES is continuing to evaluate various areas along the line for possible future changes in depth of cover.

Exposed Pipe

Specific areas of exposed pipe were identified as part of the overall depth of cover survey. Exposed pipe, while reducing the chance of accidental damage from excavation strikes, is a concern because of the increased vulnerability to outside force damage other than excavation (e.g., vandalism), and the potential for coating deterioration and atmospheric corrosion.

It is not clear whether an exposed pipe has more risk of third party damage than buried pipe. It is often assumed that shallow burial, less than six inches, for example, is worse than a full exposure since the cover is inadequate to provide much protection, but does conceal the presence of the line.

Exposed pipe was surveyed during the winter of 1998-1999, which includes both intentional (such as some stream crossings) and unintentional exposures. A total of 137 instances of exposed pipe were documented, ranging in length from one foot to 1200 feet . The total lengths of exposed pipe occurring in pipeline segments from pump station to pump station are shown in Figure 5-9. This survey is more detailed and recent than the one described in the Kiefner and Associates audit (Johnston, 1999). Figure 5-10 shows the instances of exposed pipe in more detail for the Edwards Aquifer zone.

5.3.5 Crossings

Like most pipelines, the Longhorn pipeline crosses creeks and rivers as well as man-made linear features such as roads, railroads, or other pipelines. These crossings are potentially vulnerable points along the pipeline. Rivers and creeks are subject to erosion that can dislodge the pipeline. Vehicle traffic on roads and railroads can cause recurring stresses and vibrations in the subsurface. For these reasons, pipelines are fortified at crossings and protective measures are specified depending on the circumstances. These can include thicker wall pipe and increasing depth of burial and casings at road and railroad crossings.

Stream and River Crossings

There are two primary issues associated with stream crossings: conditions that would contribute to a line failure and the sensitivity of the crossing to a petroleum product spill.

The Longhorn pipeline crosses several large rivers and numerous creeks. The crossings were built under two different sets of specifications, depending on when the crossing was built or upgraded. Crossings can be elevated over a stream or be subsurface and below the stream bed. There are some elevated crossings in the system. However, crossings for new pipeline have been installed by directional drilling (except for one which was conventionally bored) to provide better cover. Heavy-walled pipe was used. Since 1997, portions of the former EPC pipeline have been refurbished, including stream crossings. The 600-ft James River crossing was lowered. The line was further lowered in two locations in Kimble County. Also, the crossings of Whiskey, Beaver, and Bear Creeks were lowered to 3 ½ ft, 2 ft rock, and 4 ft of cover, respectively.

In an audit report by Kiefner and Associates, replacement of the Rabb's Creek Crossing, not far from the old Warda Station, was recommended (Johnston, 1999). This small creek crossing is scheduled for replacement because the crossing supports have deteriorated and the vertical column supports have corroded. It has also been observed that at the Marble Creek crossing near Austin, a tributary of Onion Creek, one of the pipe bridge supports has been displaced from the vertical and leans in a downstream direction.

Field observations of some of the elevated crossings for the Longhorn system suggest that some of this pipe could need a closer coating examination and possible coating replacement or repainting. There were sections in the Houston and Austin areas where the protective layer had been peeled away or had deteriorated.

Erosion of the embankment and bottom scour are threats to crossings. In the history of the EPC system, there were several instances where pipe was exposed or damaged from unstable embankment areas and required remediation or repair. These cases include:

- The James River crossing in Mason County, which experienced a washout during flood conditions that resulted in dislodgment of the pipe from the stream. This did not occur while the pipeline was in operation and, in fact, appears to have occurred precisely because the pipe was empty due to shutdown. It floated and was displaced by the flowing water. Had flooding occurred when the pipe was in service, this incident might not have happened.
- In 1991 and again in 1995, action was taken at the Brazos River crossing. Rip rap was placed under, around, and above the 18-inch pipeline to repair erosion in the river bed. Then in 1995 the crossing was replaced.
- In 1993, the pipe was exposed in the Colorado River. Eighty feet of exposed 18-inch pipe was covered with sand bags to provide additional cover and an erosion or scour barrier.

It was also noted that smaller stream and drainage ditch crossings in the Houston area, where there is potential vulnerability to vandalism, show evidence of use as foot bridges, graffiti painting, and tampering with the protective coatings. At one crossing, measures had been taken to counter such activities by placing a barrier fence at each end to restrict use of the pipe as a bridge. Short sections at either end, where the pipe emerged from burial, were still accessible. Longhorn is examining major crossings as part of its pipeline refurbishment program. Longhorn continues to evaluate and correct problem crossings.

Road and Railroad Crossings

Some small rural roads were trenched across, in accordance with the 1949 and the 1993 company specifications. Tunneling or casing has been used on larger roads. The subject pipeline has approximately 177 casings, mostly on the older portion, which are discussed further in Chapter 6 section on relative risk assessment. Casings were originally installed as a means to reduce the effects of vehicle loadings on the buried pipe, to provide a path for leaks to be routed and detected without damaging the road or railroad structure, and to facilitate less intrusive pipe replacements. Railroad crossings require more depth of cover than road crossings.

Casings are considered as an area of increased corrosion potential, although DOT has not found them to be a significant contributor to past accidents. They have the potential to act as a shield so that protective currents cannot reach the carrier pipe; as an environment for unobservable atmospheric corrosion; and an opportunity for a "short circuit" in which the carrier pipe becomes anodic to the casing pipe and accelerated corrosion occurs on the carrier pipe. In much of the modern construction, casings are avoided.

5.3.6 Maintenance Repairs and Rehabilitation

Proper maintenance is essential to preserving the integrity of the pipeline system. Maintenance can be divided into two parts of the System: the pipeline and facilities.

The major activities consist primarily of repairs or replacement of the following:

- CP system rectifiers and electrical circuitry;
- Test leads attached to the pipe;
- Casings and casing/pipe electrical isolation for road and railroad crossings;
- Pipe protective coatings, including paint on aboveground pipe and components;
- Pipe segments;
- Block and check valves;
- Pressure and temperature sensors;
- Pipe bridge supports for elevated stream crossings; and
- Pump station equipment, including pumps, valves, pipe and fittings, instrumentation, controls, and tanks.

EPC maintained the System through October 1997, after which maintenance was taken over by Longhorn. A summary of the repairs performed from 1988 through 1998 are summarized in Table 5-18.

5.4 PUMP STATIONS AND MAINLINE BLOCK VALVES

Pump stations and valves are important parts of the pipeline system and significant to its integrity. They are potential sources of leaks themselves and affect pressure conditions in the piping. The factors affecting the integrity of the existing and proposed pump stations and mainline valves on the pipeline from Galena Park to El Paso are discussed and described in this section. Pump stations and valves are discussed separately from the pipe portions of the pipeline. They consist of equipment items and configurations that can be examined individually to evaluate their integrity and potential risk.

5.4.1 Pump Stations and El Paso Terminal

The purpose of pump stations along the pipeline is to provide the driving force to maintain liquid product flow at a desired flow rate through the pipeline from Galena Park to El Paso. The stations are located along the pipeline at distances that are primarily determined by the pipeline elevation profile, the product characteristics, and the desired product flow rate. The liquid product enters each station at a relatively low pressure, and the pressure is increased through the station pumps.

Pump Station Description

There are five newly constructed pump stations located along the pipeline route from Galena Park to El Paso. A new terminal has also been built at El Paso. As an example of a “typical” pump station, a simplified flow diagram of the Cedar Valley Station is provided in Figure 5-11. This particular station design is also used for the Kimble County Station and will be used for the majority of the additional stations that are needed to reach a product flow rate of 225,000 bpd.

In this pump station, the product enters from the upstream side of the station and passes through a strainer to remove any entrained particulate matter. The product then passes successively through the two pumps in series where the pressure is increased to the level needed to maintain the desired flow rate to the next downstream pump station. At some stations, pumps may be operated in parallel configuration.) The pressure at the outlet of the second pump is regulated by a pressure control valve to prevent excessively high pressure in the line. The outlet pressure is regulated at or below the MOP. Check valves in each pump bypass line and in the mainline bypass line prevent recirculation or reverse flow of the product back through the line in the event of a pump shutdown or valve closure. These check valves also permit the product to bypass either or both of the pumps.

Other major equipment present at some or all of the pump stations include relief and storage tanks, booster pumps, scraper (pig) launchers and receivers, meter provers, pressure relief tanks, and sump tanks. Tanks are only located at Satsuma Station, Crane Station, and the El Paso Terminal. Scraper launchers and/or receivers are installed at Galena Park, Satsuma, Crane, and El Paso. These launchers and receivers are used for pigging.

All of the pumps are centrifugal models equipped with single mechanical seals. The pumps at the Galena Park and Kimble County stations are single stage, but the pumps at the other stations are multi-stage pumps, with the number of stages varying from two (Cedar Valley) to six (Crane). With the exception of one new mainline pump installed at the Crane Station, all the mainline pumps in the new stations are refurbished pumps originally removed from other stations taken out of service or dismantled. Refurbishment can include inspection, trimming the impellers to match performance, trimming the seals as needed to be compatible with all of the pumped products, and repairing any deficiencies.

The pumps are all driven by weather-protected (WP) Type II electric motors. The electrical systems and circuits are designed to meet or exceed National Electric Code (NEC) and Underwriters Laboratory (UL) specifications to protect against ignition in hazardous atmospheres.

The suction and discharge pressures of all pumps are also included in Table 5-19. These pressures are projected for the line when transporting fuel oil as the refined product, since the pressures are highest when transporting heavier products such as fuel oil, compared to lighter products like gasoline. The overall average pressures and many of the pressure extremes along the pipeline are highest at the higher capacities with fuel oil. In several instances, the pump discharge pressures closely approach or are equal to the MOP. At locations where the pump discharge pressures can exceed the MOP, the discharge line pressures are reduced and controlled by throttling through pressure control valves (PCV).

The number of block/control valves and flanges over two inches in diameter and in liquid product service were estimated from the piping and instrumentation diagrams (PIDs) for each pump station or from permit applications for the El Paso Terminal. These estimates are shown in Table 5-19 for all three design flow rates. Check valves are not included in the estimates.

Although not explicitly described in the Longhorn Project Description, it is assumed that the additional pump stations needed for the highest-capacity case would all be similar to the Cedar Valley design.

These component counts are used to develop estimates of fugitive hydrocarbon losses from the valves, pumps and, in the aggregate, from pump stations and the El Paso Terminal.

Most of the valves of interest to System integrity are large block or control valves in the size range of 10 to 20 inches. There are also a number of small valves, usually one inch or less in size, associated with instrumentation, and particularly, with thermal safety valves (TSVs). TSVs are installed on any segment of pipe in liquid service that could be blocked in under any circumstance. A blocked-in segment of line could be heated by the sun, ambient air, or other sources. The liquid within the pipe segment could expand and, without the TSVs, could cause the pipe or associated valves to rupture. Pressure due to liquid expansion causes a TSV to open and drain liquid to the sump tank, thus preventing damage and a possible release of product.

Station Operations

The operation of each pump station is controlled by a combination of local control systems and remote operators monitoring a centralized SCADA system located at the WES Tulsa Operations Control Center. Some additional details are provided in Appendix 5E. Each source transmitting data to the SCADA system is monitored every five to 10 seconds. The signals are electronically transmitted to the Tulsa Operations Control Center by satellite communications. Telephone modems are in place as a backup to the satellite system. The modem system can be used if there is an isolated failure in satellite communications from individual stations or if there is a failure of the entire satellite system. When all locations are being accessed with the backup modem system, the scan intervals increase significantly, and can be as much as three and a half minutes when scanning all parameters at all stations.

For the purposes of monitoring and control, the WES pipeline system is divided into three zones: south, central, and north. The Longhorn pipeline will be assigned to the south zone. Each zone is under the control of one operator (controller). Controllers monitor the pipeline operations around the clock, working 12-hour shifts. A supervisor is also present in the Control Center on weekdays and on call at other times. Each of the controllers is familiar with the operations in all three zones.

Controllers can start and stop flow of product into the pipeline from supply points, start and stop pumps, operate valves, and monitor pipeline pressures, flow rates, product densities, and temperatures. However, local control systems provide much of the protection against abnormal operation at each of the pump stations. Table 5-20 lists emergency shutdown alarms and devices located at pump stations. These local control systems are designed to provide an orderly shutdown of the pump station if an alarm condition occurs or if certain operating parameters are violated. At the same time that the shutdown sequence has been initiated, a shutdown alarm is transmitted to the Tulsa Operations Control Center.

As an example of local control, a low suction pressure (typically less than 50 psig at several stations) will cause the pump to automatically shut down. A pump discharge pressure above a specific pressure setting will also produce an automatic pump shutdown. Other sensors and controllers act in a similar manner. The primary objective of these local controls is to prevent abnormal operations from damaging the pipeline and pump station equipment and potentially cause leaks. However, the capability to detect leaks already in progress and to respond with appropriate action resides primarily with the controllers in the Tulsa Operations Control Center.

5.4.2 Mainline Block Valves

There are both block and check valves located on the Longhorn pipeline. Block valves are located at pump stations and other strategic points along the pipeline. Block valves are placed to minimize draindown during maintenance and to minimize potential spill volumes. Check valves prevent back flow and draindown in the event of an upstream failure or a flow reversal. The characteristics and locations of these valves are described and discussed in this section. Also presented are estimated maximum leak/spill volumes for selected sensitive locations.

The location and types of mainline valves on the existing Longhorn pipeline are listed in Table 5-21. The valves on the section of the pipeline between the Galena Park and Satsuma stations are 20 inches in diameter. The mainline valves from Satsuma Station west are all 18 inches in diameter.

The block valves are all gate valves, and the check valves are reported to be swing type. All valves are constructed of steel and have an ANSI rating of 600 psi. The valves are manufactured by companies such as Daniels, Cooper, WKM, U.S. Steel, and Kerotest. As part of the pipeline refurbishment, all mainline valves were removed from the line, refurbished, and placed back in the pipeline. There are 17 block valves that are remotely controlled from the

Control Center. Closure time for the remotely controlled block valves ranges from 90 seconds to 3.2 minutes depending on supplier and model (Willbros, 1998).

The mainline valves are installed in locations that can isolate the pumping stations, protect certain environmentally sensitive areas, or isolate sections in long segments of the pipeline unbroken by pumping stations. There are remote-controlled valves on the eastern (upstream) side of several environmentally sensitive area crossings. These valves are often paired with a check valve and a manually-operated valve on the western side of the crossings. In the event of a pipeline leak in the sensitive areas, these valves can prevent additional drainage from upstream and downstream sections of the pipeline into the sensitive areas. Appendix 5F presents further information.

5.5 SPILL AND EMERGENCY RESPONSE PLANS

This subsection deals with the response of Longhorn, contractors, and public agencies to a pipeline spill: compliance with regulations, adequate planning/preparations to protect sensitive areas, response time, and coordination between various response entities. Each of these issues is discussed below.

5.5.1 Compliance with Regulations

Planning and responding to spills from pipeline operations is regulated under several different Federal and state programs, including:

- 49 CFR Part 194;
- 49 CFR Part 195;
- Oil Pollution Act of 1990;
- OSHA HAZWOPER; and
- Texas Natural Resource Conservation Commission (TNRCC) Spill Prevention and Control (Chapter 327).

In addition, there are various industry guidelines that suggest the format and content of an appropriate emergency planning program. The ANSI B31.4 is an example of such a guideline that was used for comparison to the Longhorn emergency response planning.

Two emergency response planning documents that apply to the Longhorn pipeline were reviewed:

- Longhorn Pipeline Oil Spill Facility Response Plan (FRP);
  - Volume I Core Plan;
  - Volume II Zone and Facility Plans; and
- WES System of Operating Manuals, Volume: Emergency Response Plan (ERP).

The FRP is specific to the Longhorn pipeline and was developed primarily to comply with the requirements of OPA '90 and 49 CFR Part 194. The plan was submitted to DOT on November 2, 1998 for review and approval.

The FRP provides information on spill response planning, training, resources and procedures. The plan includes:

- Notification procedures for initiating a response and for regulatory reporting;
- Release detection procedures and release mitigation procedures;
- Description of initial response actions, including immediate response steps, securing the source of the spill, safety and health considerations, storage/disposal of waste materials, endangered species and wildlife rehabilitation, and documentation of the response;
- Description of response teams and their responsibilities (all operations and maintenance personnel have the authority to act as the Incident Commander/ Qualified Individual);
- Communication equipment;
- Personnel and resources available for responding to a spill, including Longhorn and oil spill response contractors. (Employees are generally located within a one-hour response time along the pipeline. Longhorn has response agreements with emergency response contractors that have equipment and personnel located in Houston, San Antonio, Austin, Eastland, Midland/Odessa, and El Paso. The contractors are expected to meet or exceed the requirements of 49 CFR Part 194); and
- Containment and diversion booming strategies to protect human life and sensitive resources.

The pipeline is mapped on 1:100,000 U.S. Geological Survey (USGS) topographic maps that indicate any lakes, rivers, and streams within five miles of the pipeline. (The topographic maps also indicate the potential down gradient flow direction from the pipeline locations. Environmentally-sensitive areas are mapped within a radius of one mile of the pipeline per 49 CFR §194.103. Beyond 49 CFR Part 194 requirements, detailed mapping on USGS 7.5 minute topographic maps is included for at least 15-miles downstream on river crossings and in the Houston and Austin areas. Mapping also includes aerial photos of the Houston and Austin areas.)

The spill training program for field employees includes spill response training, incident command training, and OSHA's HAZWOPER training. Tabletop exercises are included as part of the spill training. Longhorn encourages local response agencies to participate in periodic tabletop and spill response exercises.

An Austin Sub-Area Plan was prepared to provide more detailed response information beyond the scope of OPA Plan requirements. This plan includes map locations for known caves and detailed response strategies for the creek crossings in the Austin area.

Longhorn will meet yearly with Local Emergency Planning Committees (LEPCs) to ensure appropriate emergency response awareness.

Volume I presents emergency planning information that is general in nature and common to all portions of the pipeline. Volume II addresses specific response zones and sensitive areas within those response zones. The plan specifies two response zones:

- Sugar Land Zone — Covers the pipeline from Harris to Llano counties; and
- Hobbs Zone — Covers the pipeline from Mason to El Paso counties.

Within each of these two response zones, a number of sensitive areas have been identified for a higher degree of specific planning:

- Environmentally Sensitive Areas (ESAs); and
- Work Site Response Plans (WSRPs).

The regulations and guidelines listed above were analyzed to extract individual requirements to facilitate a detailed compliance evaluation. The ERP, part of the system of operating manuals, addresses DOT, OSHA, and EPA requirements for emergency operations. The ERP is incorporated as part of the Pipeline Oil Spill FRP. Detailed requirements of emergency response regulations, a cross reference to the portions of the Longhorn FRP and/or ERP that apply to that requirement, and a compliance status comment are summarized in Appendices 5G, 5H, 5I, and 5J.

The Longhorn FRP and ERP appear to satisfy the requirements for emergency planning and preparedness in the applicable regulations. Table 5-22 summarizes the apparent regulatory compliance status and includes the few compliance issues that were noted in the detailed review.

5.5.2 Sensitive Areas Response

This subsection addresses how the Longhorn FRP has identified and planned response for sensitive areas along the pipeline. As discussed in the previous subsection, Volume II of the FRP includes ESAs and WSRPs in Section 4 to address specific response issues. The ESAs are multi-page tabular presentations of emergency planning information that include:

- Location information;
- Size of a worst-case leak;
- Locations of the nearest upstream and downstream mainline valves;
- Estimated response times for Longhorn and contractor personnel;
- Local emergency management agencies, contact numbers, and capabilities;
- Listing of environmentally sensitive areas downgradient from the pipeline section;
- Contractor resources that would be used in the response;
- Access information; and
- Cautions.

WSRPs are done for selected ESAs. The WSRPs are on a folded 11x17 page presented in a color page layout format. The WSRPs include:

- Color map showing the route to access the site;
- Tabular driving directions to access the site;
- Text box containing the response strategy;
- Tables estimating the personnel and equipment required to implement the response;
- Photos and/or drawings illustrating the implementation of the strategy (such as where booms or dams would be installed, where the vacuum truck would park and similar considerations); and
- Series of photos assembled into a panoramic view of the site with annotations added for directions of flow of any water bodies.

Section 4 of the FRP also includes a detailed set of pipeline routing maps that show highways, population centers, schools, hospitals, parks/recreation areas, aquifers, water intakes, and waterways. These maps have been further annotated to show areas of known karst formations (caves) and potential work sites downgradient of the pipeline.

For the purposes of this EA study, sensitive areas were defined in terms of water crossings, karst formations, special land use, and population density. These are discussed in Chapter 4 of this report. Table 5-23 shows the total numbers of ESAs and WSRPs in each metropolitan area within the zones identified in the FRP, compared to the numbers of special land use areas identified in this study. Potential ESAs or WSRPs for the EL Paso metropolitan area have not been identified because the final route in this area has not been determined. In evaluating the data in Table 5-23, it should be noted that the ESAs and WSRPs focus on environmentally sensitive areas and work sites where containment and removal of spilled oil could best be accomplished. The special land use areas focus more on exposure of people to a potential spill than on environmental consequences, although the parks category represents both the potential of human and environmental impacts. Longhorn has committed to enhancements in the OPA ‘90 Plan to provide expanded consideration of sensitive areas (Longhorn 1999). Changes are expected to the current Plan. These changes include establishing liaison with the LEPC and emergency response agencies (Longhorn, 1999). The data in Table 5-23 are presented to give an overview of the current level of sensitive area response planning.

5.5.3 Recent Emergency Response Experience

An explosion occurred on the Longhorn pipeline near the Wood Bayou subdivision in Harris County at 11:30 AM on October 7, 1998. The pipeline was not in service at the time. It was being tested using a smart pig that was propelled through the pipeline by diesel fuel. It is estimated that 1,000 bbl of diesel fuel were released from the pipeline, much of which is thought to have been consumed by fire. One person was injured with first-degree burns.

The Houston Fire Department was first to respond to the site and assumed control of the incident. Exposed power lines hampered early response. Longhorn personnel and their response contractor, Boots and Coots (B&C), were on the scene within two hours. Oil was reported in Hunting Bayou about three hours after the incident, and B&C began deploying containment booms and absorbent pads within 35 minutes of that report. These were critical to preventing more widespread contamination. A limited assessment near the release site was started within five hours of the release. Notifications were made to federal and State of Texas agencies, and many of these agencies dispatched inspectors to the site. Plans for containment, recovery, and cleanup were developed and reviewed with agency personnel. These containment and cleanup operations were implemented early on October 8. An under-flow dam was built in the gully near the spill site. Hard containment booms and absorbent booms were installed in the upper and lower creek areas, in addition to those already in place in Hunting Bayou. Soil, water, and air samples were collected. After all containment was in place and the site was secured, removal of contaminated soil began on October 10. All site cleanup activities were completed by October 15.

As a result of the cleanup activities, approximately 173 bbl of an oil/water mixture were recovered from Hunting Bayou, of which about 141 bbl were believed to be diesel fuel (Capitol, 1999)**.** One hundred and thirty-six soil and water samples were collected to establish the degree of contamination and also to confirm that the cleanup had been successful. The results show that the excavation actions and other cleanup activities undertaken by the emergency response coordinator were successful in remediating the contaminated soils and water.

"Soils remaining in-place upon completion of the remediation activity were found to have petroleum concentrations below the (TNRCC established site-specific) cleanup level of 100 mg/kg." (Capitol, 1999)

Approximately 780 cubic yards of soil were removed and sent off-site for disposal. The majority of the contaminated soil (580 cubic yards) was disposed of as Class II non-hazardous waste and the remainder as Class I non-hazardous waste. A 20 cubic yard roll-off box and two 55-gallon drums of contaminated debris were also disposed of as Class I non-hazardous waste by the response coordinator.

A Natural Resource Damage Assessment (NRDA) of preliminary injury was performed by the emergency response coordinator due to the recovery and treatment of a single oiled bird, and the migration of diesel into Hunting Bayou. The NRDA consisted of visual inspection of the pipeline break area and surrounding areas, and inspection and collection of surface water samples from Hunting Bayou. The NRDA report commented that:

"…there were no oiled (or dead) animals, reptiles, amphibians or other forms of life observed…"

and

"...there were no instances of observed stressed vegetation as a result of the spill noted during the preliminary assessment."

The NRDA concluded that:

"Based on visual observations made during the field assessment, and the analytical data derived from the water samples of Hunting Bayou, the creek and gully, there was no evidence exhibited, either visually or analytically, that would indicate an injury to natural resources as result of the Longhorn diesel spill of October 7, 1998." (Capitol, 1999)

5.6 YEAR 2000 COMPLIANCE

5.6.1 Background and Purpose

This section includes a review of WES efforts to prepare for computer problems that could be caused by the date rollover from December 1999 to January 2000.

The scope of this task was limited to computer systems that have a direct impact on pipeline operation. This would include control systems and "smart" devices on the pipeline itself, the SCADA network between the pipeline and WES' operations center, and the SCADA system computers.

In dealing with Y2K issues, it is important to remember that there are no universal "standards" to "comply" with, so that the frequently used phrase "Y2K Compliance," does not have specific meaning. All organizations, WES included, must adopt internal standards for dealing with Y2K issues that are appropriate to their business.

The basic questions that this task addresses are:

- Does WES have a plan and project in place for Y2K readiness?
- Are WES efforts consistent with other industry efforts?
- Is the Y2K project adhering to plan and on schedule?
- Is the plan complete with regard to the Longhorn pipeline?

The following statement was provided by Longhorn under the protection of the "Year 2000 Information and Readiness Disclosure Act" of the 105th U.S. Congress:

> "Longhorn initiated an enterprise-wide project on January 4, 1998, and WES initiated an enterprise-wide project in 1997 to address the year 2000 readiness issue for both traditional information technology areas and non-traditional areas, including embedded technology. This project focuses on all technology hardware and software, external interfaces with customers and suppliers, operations process control, automation and

instrumentation systems, and facility items. The phases of the project are awareness, inventory and assessment, renovation and replacement, testing, validation, and contingency planning.

The awareness, inventory, and assessment phases of this project as they relate to both traditional and non-traditional information technology areas have been completed. During the inventory and assessment phase, all systems with possible year 2000 implications were inventoried and classified into a qualitative risk assessment matrix that evaluates the potential Year 2000 implications using a nine-point scale of likelihood of occurrence and a nine-point scale of severity of consequences.

Renovation or replacement, testing, and validation of critical systems is expected to be completed by September 1, 1999. Testing and validation activities have begun and will continue throughout the process. However, certain non-critical systems may not be compliant by January 1, 2000.

Williams Energy Services and Longhorn have initiated a formal communications process with other companies to determine the extent to which those companies are addressing their Year 2000 compliance. Where necessary, Williams Energy Services and Longhorn will be working with key business partners to reduce the risk of an interruption in service or supply and with non-compliant companies to mitigate any material adverse effect on Williams Energy Services and Longhorn. Williams Energy Services and Longhorn expect to utilize both internal resources and external contractors to complete the Year 2000 Compliance project.

In situations where planned system implementations will not be in service in a timely manner, alternative steps are being taken to make existing systems compliant."

The systems listed in Table 5-24 have all been classified in category one except the Terminal Information Manager System, which is a category four system.

The Longhorn management team will receive a monthly score card indicating the status of activities in the Williams and Longhorn Y2K project that directly relate to Longhorn's operation.

5.6.2 Year 2000 Plan

A copy of WES' "Y2K Compliance Manual" dated November 4, 1998, is available on their website at http://www.williams.com/y2k/compliancemanual/default.htm. Figure 5-12 shows the table of contents of WES' "Y2K Compliance Manual."

There are several key elements for an enterprise-wide Y2K effort that must be considered. Following is a list of key elements:

- **Accountability –** This includes sponsorship and review by senior officers in the organization, and a designated Y2K Project Manager or Project Office. It also includes documentation on all project phases.
- **Definition of a "Standard" for "Compliance" –** The computer systems being evaluated must be held to a consistent standard.
- **Completeness –** The project must encompass software, hardware, and embedded systems. It must also include interfaces with outside organizations that could impact the business (supplier-chain evaluation).

WES' Y2K Compliance Project meets the accountability requirement. There is an established Y2K Project Office (YPO) with oversight from the Chief Information Officer. Documentation is required for most project phases. Figure 5-13 provides an example of the documentation required for certification of a single component. The "deliverables" section outlines reporting requirements for monthly scorecards and status summaries.

The Compliance Plan defines a standard for compliance (the "Y2K Compliance Definition") and also compliance ratings ("Compliant," "Not Compliant," "Not Tested," and "Unknown"). The "Compliance Standards Reference Guide" section also lists guidelines for testing compliance.

As presented in the compliance manual, WES' Y2K project is complete for the Longhorn pipeline operation. WES is required by the plan to address all of the components and systems required to operate the Longhorn pipeline. This includes embedded systems (programmable logic controllers and "smart" instruments) and interfaces to external systems (e.g., tele-communications).

In assessing internal systems, most organizations have taken a stepwise approach:

- **Awareness –** Communication with the organization's staff to make sure all are aware of Y2K issues.
- **Inventory –** Inclusion of every item, including software, hardware, and embedded systems.
- **Assessment –** Typically, inventoried items are prioritized. (Vendor certification or in-house testing determines Y2K Readiness. This is most often a component-level assessment.)
- **Remediation –** Renovation or replacement of any component-level problems identified in assessment.
- **Systems Testing –** Testing of complete systems after all remediation work is completed, to validate "compliance."

- **Problem Management and Continuity Planning –** Establishment of plans and teams for handling any problems that may arise.

The Compliance Plan outlines all of these elements in the "Methodology" section.

5.6.3 Comparison to Industry Guidance

Figure 5-14 is a summary of WES' Y2K status, as presented to the API in March 1999. WES' efforts address all the major areas that the API Y2K task force has identified. The status report indicates that they are in the remediation and systems testing phase on all critical tasks, which is somewhat ahead of the industry as a whole.

5.6.4 Adherence to Plan

As demonstrated in Figure 5-14, WES' Y2K project is on schedule. Inventory and assessment are complete, remediation is underway or nearly complete, and systems testing is being implemented.

5.6.5 Completeness – Risk Issues

No issues were identified. The project plan requires WES to address all elements of the pipeline control and SCADA system, including "smart" instruments, programmable logic controllers, remote terminal units, telecommunications interfaces, and the computers, network, and software in the pipeline control center.

5.7 LEAK HISTORY

This section reviews the leak history of the sections of EPC pipeline. It also compares EPC data to national and other company data.

5.7.1 Background and Purpose

This section analyzes the spill history of the EPC pipeline system assets that now comprise the System. The purpose is to determine the frequency, causes, and consequences of previous leaks and spills, as an indicator of possible future performance.

Several sources of EPC spill data were reviewed for this evaluation. A comprehensive list of EPC accidents was assembled from the various sources and then analyzed. The analysis compares the former EPC pipeline data with those of other comparable companies and with national averages. The data are used as a measure of realistic performance expectations in developing event probabilities for the probabilistic risk assessment in Chapter 6.

5.7.2 Data Sources

The EPC and Longhorn files were reviewed for sources of information on the spill history for the EPC system assets, now owned by Longhorn. The following sources were available:

- Copies of incident report forms were provided by Longhorn for 114 EPC spills. The information was provided in a variety of formats, including: EPC internal company incident forms, DOT reportable incident forms, and RRC H-8 forms. Forty-three of these address spills were 50 bbl or greater.
- Fluor Daniels Williams Brothers Company (FDWBC) Due Diligence Report, Environmental Site Assessment (ESA) Phase I cites 174 accidents (145 at pump stations and 29 on the pipeline) from a search of EPC records (FDWBC). The report includes 57 spills above the DOT reporting threshold of 50 bbl and 117 accidents below the threshold value.
- Kiefner and Associates "Audit of Existing Portions of Longhorn Pipeline" (Johnston, 1999) document lists 23 DOT reportable spills of various sizes attributed to Longhorn-owned assets.
- Memorandum by R.L. Deaver, "Longhorn Project – Analysis of DOT Accident Reports on Exxon Pipeline Company" (Deaver, 1998) lists 26 spills obtained from DOT records by a Freedom of Information Act (FOIA) request. Deaver's analysis compared the DOT reportable records to the 53 spills in the FDWBC report. Deaver did not address a few spills in the Satsuma to Moore Road segment of the EPC line, which were in the FDWBC report.

The first source listed above contained copies of the original documents, some of which included the stamp indicating transmission to DOT as an accident report. The last two sources only summarized the accident reports cited in source numbers 1 and 2. The original forms, with more detailed information on each accident, were not included in the latter sources.

Data were obtained on other liquid pipeline company spills for comparative purposes. Sources for this information included:

- The DOT/OPS website, www.ops.dot.gov, which presents summary spill statistics for hazardous liquid pipeline operators;
- A data analysis of average national hazardous liquid pipeline and specific company corporate performance from spill data in the national DOT database (Allegro, 1999); and

- The RRC H-8 data on all EPC pipeline and all Company A pipeline assets in the counties through which the Longhorn pipeline runs. The Company A crude oil pipeline runs along a similar route and was constructed around the same period as the EPC system. It could provide another comparative point for the EPC pipeline leak history. This data source was of limited use since the RRC database contains a summary spreadsheet, but not copies of the original H-8 forms. These data were not used in the analysis since the spills attributable to the pipeline and pump stations could not be readily separated from those of other EPC and Company A assets.

5.7.3 Spills Database

A database was assembled from the sources listed in the previous section that contained the most comprehensive list possible for EPC spills. A database was assembled starting with the copies of the incident report forms, supplemented by other data on spills which had no accompanying report form, but were listed and referenced in the sources discussed in Section 5.7.2. The resulting database contains 177 spills, 60 of which are over the DOT reportable threshold of 50 bbl. DOT regulations define reportable events as spills or leaks of 50 bbl or greater; events where an injury or death occurred; or where financial damage exceeded a DOT-specified threshold or where a fire or explosion occurred (49 CFR §195.50). In comparison, the RRC requires all oil producers in the state to report crude oil spills of 5 bbl or larger on Form H-8.

Table 5-25 shows the sources of data and the size of spills within each data set. The cumulative database was audited for consistency to ensure that no incident reports were ignored. Dates and volumes were reviewed from the various data sets to ensure that spills were neither double counted or overlooked. The FDWBC was the most comprehensive, containing 174 of the 177 known spills.

The cumulative database contained 60 spills of 50 or greater bbl. Fifty-seven of these sixty spills were in FDWBC data tables. Forty-two of these 60 spills also had EPC report forms provided by Longhorn. One additional incident report was provided by Deaver (Deaver, 1998).

5.7.4 Spill Frequency and Volumes

The spill data were analyzed in two sets, one for the subset of larger accidents of 50 bbl or greater, and one for all spills. These data were used as the basis for probability determinations in the probabilistic risk assessment of Chapter 6.

Analysis of All Accidents

The database of 177 accidents included some small spills (less than 5 bbl) as well as those of 5 bbl and greater. The spill frequency for "all EPC accidents" was 1.36×10^{-2} spills/mile/year (177 spills/450 miles/29 years). However, these small spills contributed a negligible amount to the overall spill volume. The total volume released for the subset of spills that were less than 50 bbl was only 1,430 bbl, while the total volume released for all spills was 111,129 bbl (109,699 + 1,430). The average volume released per spill for the 117 accidents not included in the "Spills of 50 bbl or greater" database was 12.2 bbl/spill (1,430 bbl/117 spills).

Table 5-26 shows the distribution of spill volume and number of spills split between pipe and pump stations for all sizes of spills. The table also shows spill frequencies for various size ranges. The majority of spills on the EPC system occurred at pump stations.

Analysis of Spills of 50 bbl or Greater

Table 5-27 lists the events with spill volumes of 50 bbl or greater for the EPC system. Figure 5-15 shows the spill count data in a timeline, while Figure 5-16 shows the volume data in a timeline. This is not strictly a summary of "DOT reportable" spills, because DOT reportable spills can contain volumes less than 50 bbl if there is an injury, death, or financial damage exceeding the DOT threshold quantity. Since there are no known EPC spills with deaths or injuries, the database simply reflects spills of 50 bbl or more.

This system had 60 spills that were 50 bbl or greater in volume over a 29-year period. This results in an average of 2.1 spills of this size per year. The total volume of crude oil spilled was 109,699 bbl, an average of 3,783 bbl per year. Of the 60 spills of 50 bbl or greater, 48 (80 percent) occurred at pump stations. These events accounted for 51,003 bbl, or 46 percent of the total spilled volume. Twelve of the 60 spills of 50 bbl or greater were on the mainline only. This is 20 percent of spills of 50 bbl or greater. These spills accounted for 54 percent of the total spilled volume. Thus, on average, the EPC system had 1.7 spills per year at pump stations and 0.41 spills per year on the mainline.

When both pump stations and mainline are included, the leak history shows that among the 60 reported spills of 50 bbl or greater, the average size was 1,828 bbl. EPC experienced five spills greater than 5,000 bbl (including two greater than 20,000 bbl and one between 10,000 and 20,000 bbl). These five spills occurred in 1968, 1969, 1977, 1979, and 1990. These large spills accounted for 63.7 percent of the total volume lost in a 29-year period. The average spill size greater than 5,000 bbl was 13,970 bbl. If these five largest spills were excluded, the average spill size greater than 50 bbl would be reduced to 725 bbl.

The main pipeline had a spill frequency rate of 9.2×10^{-4} spills/year/mile (12 spills/29 years/450 miles). Figure 5-17 shows the mainline spills count data in a timeline, while Figure 5-18 shows the mainline volume data in a timeline. The average volume lost from mainline spills was 4.5 bbl/year/mile (58,696 bbl/29 years/450 miles) for the 29-year history. The average volume lost per spill on the mainline was 4,891 bbl/spill (58,696 bbl/12 incidents). The average volumes are greatly influenced by a few large spills in a few years.

The pump stations have a rate of 0.21 spills/year/ station (48 spills/29 years/8 EPC stations). Figure 5-19 shows the pump station spill count data in a timeline, while Figure 5-20 shows the pump station volume data in a timeline. The average spill volume for pump stations was 220 bbl/year/station (51,003 bbl/29 years/8 stations) for the 29 years of record-keeping history. The average volume per station-year is greatly influenced by two events: 8,550 bbl spilled in 1969 and 10,500 bbl spilled in 1977. If these two spills were excluded from the analysis, the station average spill volume would be 138 bbl/year/station.

5.7.5 Leak and Spill Causes

This section analyzes the causes of the spills of 50 bbl or greater. As noted above, one of the primary causes of EPC spills was pump station leaks. A distinction is made between the pipeline pump stations because of important differences in factors that cause releases and in the consequences of releases. While pipe failures are more likely associated with pipe corrosion or outside forces, leaks or spills at pump stations can be the result of a variety of other unique causes. These causes include rotating equipment mechanical failures (e.g., pump seal failures), tank corrosion, or operating errors (e.g., not taking action to stop a relief tank overflow caused by equipment malfunction). Figure 5-21 shows the causes for the 48 pump station spills greater than 50 bbl in size. The leading cause was equipment failure, followed by corrosion, and repair and installation activities. For mainline pipe, Figure 5-22 shows the causes for the 12 spills greater than 50 bbl in size. The leading cause was outside force, which accounted for 58 percent of these events. Corrosion was the second highest cause, at 17 percent of the events.

Summary profiles of all the reported leaks at pump stations and on the EPC pipeline are also presented in Tables 5-28 and 5-29. The leak records cover a period of approximately 30 years from November 17, 1966 through May 13, 1995.

The size of the leaks and spills ranged from 0.1 bbl to 10,500 bbl. The causes of the three largest leaks are shown in the table footnotes. As might be expected, the smaller leaks and spills of 50 bbl or less make up the bulk, nearly 70 percent, of the number of reported leaks. However, these small leaks account for less than three percent of the total volume of material spilled. The fewer large leaks account for most of the total releases over the reporting period. The three largest releases are responsible for nearly half of the total volume released over the 30-year reporting period. The largest 13 of the 148 leaks make up almost 90 percent of the total volume spilled.

The specific cause of release was not listed for nearly half of the reported leaks. Most of the listed causes of releases were either corrosion or equipment failures. Of the equipment failures at stations, six were due to pump seal failures. The largest release due to a pump seal failure was 150 bbl. There were also nine failures associated with station valves, four of which were due to valve flange gasket failures, with the remaining five caused by failures of the valves themselves. Eleven releases occurred during equipment replacement or repair, but after 1971, no releases due to this type of incident were reported.

The Kemper Station along the EPC line had 18 tanks. Eleven of the leaks with identified causes attributed to pump stations were due to tank losses at the Kemper Station. There will be only three locations on the Longhorn Pipeline that will have product tanks: the Satsuma Station (1 relief tank); the Crane Station (4 tanks); and the El Paso Terminal (19 tanks).

The causes and frequency of leaks and spills at pump stations are used to develop pump station leak probabilities that were used in the risk assessment of Chapter 6.

5.7.6 Trends

The trend in incident frequency over time was examined for the “spills of 50 bbl or greater” database. The annual incident rate has been variable over the years of EPC pipeline operation, as shown in the previous figures. While the average is 2.1 spills greater than 50 bbl/yr over the 29-year period, there were seven years with no spills greater than 50 bbl, and three years with five or more spills greater than 50 bbl.

The annual spill rate shows a downward trend over the 29-year period of operation, as shown by Figure 5-23. This figure shows five-year averages of pipeline spill counts. With the exception of 1966-70, there has been a continuous decline in the spill frequency. Such a trend indicates a learning curve, where performance improves as causes are identified and corrected, and the operator learns to improve performance.

The EPC spill history was also examined to determine if the frequency of accidents varied geographically, a possible indication of a "geographic factor." All EPC accidents of 50 bbl or greater have occurred within eight of the 17 counties crossed by the pipeline. Thus, nine of the counties have never experienced a spill of 50 or greater bbl of crude oil. In fact, most EPC reportable spills have occurred within Crane, Reagan, and Harris counties, as shown in Table 5-30 and Figure 5-24. Crane and Regan counties account for 60 percent of these spills.

Many of the EPC spills occurred at pump stations. Longhorn has revised pump station locations from the previous EPC operation. When the pump station data are excluded, Kimble, Travis, and Harris counties have the most spills, as shown in Figure 5-25. When the resulting pipe-only spill count is normalized by pipe length per county, Crane County stands out as having a higher spill rate than the other counties, as shown in Figure 5-26. The high mainline spill rate in Crane County may be due to incorrect assignment of pump station leaks to the mainline; Crane County has a very small pipeline mileage. If only the number of mainline accidents per county were compared, then Kimble, Travis, and Harris counties would each account for three accidents (or nine accidents total) while Crane, Bastrop, and Upton counties would each account for only one incident (or three accidents total).

5.7.7 Comparisons with Other Pipeline Spill Data

Spill rates for the EPC system were compared with national average data and with WES and Shell data to answer the following questions (Table 5-31):

- Were previous operations better or worse than national averages?
- How does the WES performance compare with EPC performance as a factor in suggesting how future operations might compare with past operations?
- Was there any difference between Exxon corporate performance (including all Exxon liquid pipeline assets) and that of other corporate operators?

It is interesting to note that there are only two cases of pipe seam-failure among the 50 bbl and greater spills. One occurred at a pump station; the other on the main pipeline. Therefore, the longitudinal welds that are a concern for this older ERW pipe have resulted in only two of the reportable spills on the EPC system. A review by Kiefner and Associates concluded that a large percentage of EPC spills (eight incidents, or 34.8 percent of the ones analyzed) was due to seam failures (Johnston, 1999). A comparison of EPC to national data and to the Kiefner and Associates data is shown in Table 5-33. However, the Kiefner and Associates review analyzed a number of very small spill volume incidents; one of the eight accidents analyzed was greater than 50 bbl. This represents 1.7 percent of the spills greater than 50 bbl. If such events occur, the majority of associated spills appear to be in the lower size range.

National Data

Hazardous liquid pipeline spill data for all hazardous liquid pipeline operators, which are available at DOT's website, were analyzed for the period from 1984 through 1998. These data, showing spill frequency, net (unrecovered) losses in bbl and mileage, yielded an average spill frequency of 1.3×10^{-3} spill/year/mile (2,961 incidents/15 years/154,000 miles), and average unrecovered spill volume of 0.754 bbl/year/mile. The average fatality rate is 1.5×10^{-5} deaths/year/mile and the injury rate is 1.06×10^{-4} injuries/year/ mile. The EPC spill frequency for the same period is $1.8\text{x}10^{-3}$ spills/year/mile, about 38 percent higher. Both the DOT and EPC data include spills from both the pipe and the pump stations.

If spill volumes are compared, the EPC unrecovered spill volume for the period is 0.30 bbl/year/mile, about 60 percent lower than the national average for hazardous liquids. The initial spill volume for EPC, based on an average recovery rate of 94 percent from the EPC spill data, is 5.0 bbl/year/mile.

Table 5-33 compares national hazardous liquid pipeline statistics to EPC statistics.

- The EPC pipeline had a higher spill frequency than the national average.
- EPC spill volume is less than the national average.
- The EPC data represent crude oil operation only, while the DOT national data are based on all reportable hazardous liquid spills.
- Reported volume from data is unrecovered volume, while EPC data are total spilled.

In addition to DOT website data, spill data from the DOT database were analyzed by a subcontractor for this report (Allegro, 1999). Using this DOT data analysis, trends in national data were developed for comparison to EPC operation. Figure 5-27 shows that the volumes of interstate hazardous liquid spills have generally decreased, while the number of spills has remained relatively constant since the 1980s. Thus, the national data tends to indicate that the severity of accidents is decreasing. The EPC data showed this same general trend.

National pipeline data, as shown in Figure 5-28, indicates that, while most of the volume comes from mainline pipe spills, a significant portion comes from pump station spills. This is similar to EPC's experience.

DOT data provide spill counts for total hazardous liquid pipeline mileage. For an analysis of crude pipeline performance, the mileage of crude pipelines must be gathered from another source. The total mileage of crude oil pipeline in the U.S. was obtained from Pennwell Maps, Inc., Houston, Texas, which reported 114,932 miles of interstate crude oil pipelines in the U.S. If this is used in conjunction with the volume of crude spilled as determined from DOT data (61,299 bbl/yr. average spilled for 1993-1998), the national average unrecovered spill frequency for crude pipelines is 0.53 bbl per/mile/year. The EPC initial spill volume of 5.0 bbl/year/mile is higher than the national average, influenced by a few large spills for the EPC system. However, the 94 percent recovery exceeds the average recovery rate for all hazardous liquid spills as was seen in comparing the overall national average spill volume of 0.754 bbl/year/mile with the EPC volume of 0.30 bbl/year/mile over a comparable period.

Other U.S. Pipeline Company Data

This section compares national spill frequency of EPC with WES and other liquid pipeline operators. Exxon (the previous operator of the EPC system) and WES (operating contractor of the Longhorn pipeline) are compared to the national averages for hazardous liquids pipelines as well as to Company A's (the company is unnamed since they are not a party to this EA process) corporate operations. It is important to note that the Exxon assets discussed in this paragraph are all interstate hazardous liquids pipelines operated by Exxon, not just the former crude oil line now owned by Longhorn.

The results of this comparison are shown in Table 5-31. Based on the overall corporate record, Exxon's spill rate and volume of spills is less than the national average. WES also has a spill frequency less than the national average. WES had a spill volume greater than the national average, which was apparently caused by a single large station or terminal spill in 1997.

Future Trends

Chapter 6 uses the spill frequency data and volume per spill data from this section to estimate probabilities of leaks and spills. However, it should be noted that future spill performance may differ from historical values for the following reasons:

- Improvements that have already occurred recently in the life of the EPC line (industry standards implemented by Exxon over the life of the line such as SCADA systems, or recent improvements such as ILI, and lowering crossings);
- Difference in future product;

- Differences in future operation (changes in pressures, flows, and improvements in operation due to WES and Longhorn practices, and improvements due to future inline inspection and repair);
- Aging of the pipeline (continuing corrosion and fatigue issues); and
- Changes in pump station configurations (improvements in station layout may mean improvements in spill performance) and changes in pump station locations (addition of stations in the future mean more risk from station spill causes).

Some of these listed reasons may increase and some may decrease the likelihood of spills.

5.8 SUMMARY OF FINDINGS

This summary presents highlights of major findings derived from the preceding sections of this chapter. The relationship between these findings, as presented here, and the physical integrity of the pipeline system is qualitative. These findings are based on a combination of technical facts and engineering judgement. The details that support them, in this chapter, are translated into quantitative estimates of system integrity in the relative and probabilistic risk assessments of Chapter 6.

Overall, the EPC pipeline has experienced a greater than average rate of accidents (leaks and spills) as compared to national average data. It also shows a decline in spill rate in the years preceding the operational shutdown in 1995. The attributes of the system and its route are directly related to potential threats to system integrity. Improvements in the physical system and operating practices by Longhorn can reduce the potential for failure and mitigate the consequences of such failures. Longhorn is now implementing these physical and operating practice improvements. Additional mitigation measures, as discussed in Chapter 9, are further opportunities to reduce risks for future operation of the system.

5.8.1 General Attributes

1) The pipeline system has a significant amount of pipe dating from about 1950. This pipe has ERW and EFW seam welds, generally considered less reliable than fabrication welds after 1970.

2) The operating pressure profile for this line is within limits consistent with the specified yield stress associated with the pipe strengths. It is also consistent with the specifications for valves, fittings, and pumps.

3) The EPC pipeline compliance history reveals two instances of areas of concern in the DOT records.

4) Leak detection capabilities from the control center seem limited at present, but are not inconsistent with industry practices. Longhorn reports planned upgrades to these capabilities..

5) There are locations of inadequate ROW clearing, reducing patrol effectiveness.

6) Data reviewed indicates some possible areas of landslide, seismic and active faulting susceptibility along the pipeline route.

7) There are missing pipe material strength data for short portions of the line.

8) The pipeline was built according to construction specifications which appear to be consistent with best practices at the time.

5.8.2 Operating Procedures

1) Longhorn is adopting the WES System Operating Manuals for their pipeline. Revisions to these manuals to address Longhorn-specific activities are planned, but details on what these changes will include have not yet been developed.

2) Longhorn has introduced a number of new procedures in the 1998-1999 period. These include the LIMS and other activities (Longhorn, 1999).

3) Current and planned operations and maintenance activities appear to be, for the most part, consistent with industry-accepted good practices.

4) Operating procedures include practices beyond regulatory requirements that are not documented in manuals. This is consistent with practice throughout the pipeline industry.

5) Review of the WES System Operating Manuals against 49 CFR Part 195, ASME B31.4, and API Recommended Practice 1129 indicates that the procedures generally meet the requirements. There were a number of items in these standards not specifically covered by the procedures.

5.8.3 Inspection and Testing

1) Based on reviews of materials of construction, inspection results, maintenance reports, and past leak history, the most likely potential problem areas in the older portions of the subject pipeline are thought to be:

- Seam weaknesses associated with low-frequency ERW pipe;
- Corrosion wall loss; and
- Dents and gouges.

2) Hydrostatic testing and ILI in 1995, followed by digs and visual inspections, revealed areas on the line that required or will require repair or replacement.

3) There is the potential for girth weld “susceptibility” to failure associated with low frequency ERW and EFW manufacturing processes in older portions of line.

4) There are uncertainties about lower girth weld “acceptability” criteria in older portions of line.

5) New ILI is planned after startup.

6) There are missing hydrostatic test records for one portion of the line.

5.8.4 Depth of Cover and Exposed Pipe

1) Depth of cover for the buried pipe is highly variable, reflecting, in part, subsurface terrain characteristics and changes over time.

2) Some sections of pipe are intentionally exposed.

3) Longhorn has identified and is evaluating shallow and exposed pipe areas.

4) There are locations of possible minor vandalism.

5.8.5 Repairs and Rehabilitation

1) There are some areas on the line that showed a repeated higher rate of repairs than other areas.

2) Some sections of the original EPC pipeline were replace by new pipe.

3) A formal risk assessment is being used to set priorities for repair activities.

5.8.6 Crossings

Certain crossings have been identified as potential problem areas and are being addressed by Longhorn.

5.8.7 Effects of Age

1) The current knowledge of the weld seam areas of the pipe is uncertain since the ILI used in 1995 was not the type that could detect cracks, which is a key issue in ERW weld integrity. However, the hydrostatic testing provided some measure of the integrity of these welds at the time it was performed.

2) The only identified age-related deterioration mechanism are fatigue and corrosion.

3) Previous integrity verifications provided a measure of confidence that deterioration mechanisms had not compromised pipeline integrity as of the test dates.

4) No significant causes of fatigue have been present since 1995, so crack-flow growth should not have occurred since the 1995 tests.

5.8.8 Corrosion Control

1) Corrosion control effectiveness for the EPC pipeline had gaps, as evidenced by CP records and ILI inspection results.

2) CIS inspections and annual surveys (1990, 1994, 1998-99) provide some indications of CP effectiveness.

3) Past EPC corrosion control practices are questionable based on requirements of relatively high levels of CP voltage and current, indicating relatively low coating effectiveness in some areas.

4) CP surveys revealed areas of shorted casings and low potentials.

5) Protection from atmospheric corrosion appears inadequate at some locations.

6) Current practices appear to have improved compared with previous practices.

7) 1995 hydrostatic pressure test and follow-up activities removed existing flaws above a certain size.

8) 1995 ILI inspections detects and allows for removal of certain types of flaws, depending upon inspection equipment and follow-up protocols.

9) No significant causes of fatigue existed since 1994, so certain types of flaw growth should not have occurred since the 1995 tests.

5.8.9 Leak History

1) The EPC system, prior to shutdown in 1995, had 60 DOT reportable spills. Of these, 12 occurred on the pipeline and 48 occurred in the pump stations or terminal. The spill rate is greater than the national average for hazardous liquid pipeline operators.

2) The primary cause of pipeline spills of 50 bbl or greater in size has been outside force (58 percent of spills of 50 bbl or greater). Corrosion is the second highest cause at 17 percent.

3) Seam splits, such as those associated with ERW pipe, have led to two spills of 50 bbl or greater on the EPC pipeline.

4) Spill frequency declined over 29 years of operation, as shown with 5-year averages of accidents.

5.8.10 Pump Stations and Valves

1) Pump stations are typical in layout and design to others in the industry.

2) Pumps and valves have been refurbished for use in the upgraded or new pump stations.

3) The surge pressure analysis is needed to identify areas of potential overpressure along the pipeline.

   - An early surge pressure study at a flow rate of 125,000 bpd was flawed because erroneous maximum allowable surge pressures were used in the analysis.
   - A review of this initial analysis indicated that surge pressures could exceed the maximum allowable surge pressures at several locations along the pipeline.
   - A new surge pressure analyses is reportedly in progress for the 125,000 bpd, 225,000 bpd, and 72,000 bpd cases, in that order. The surge analysis is based on fuel oil as the operating fluid as its density yields the highest surge pressure values.

5.8.11 Spill Response

1) The Longhorn pipeline is substantially in compliance with Federal and Texas emergency response regulations.

2) The Longhorn Facility Response Plan exceeds the regulatory requirements in a number of areas, including the level of detail in the Work Site Response Plans.

3) The emergency response planning is consistent with that for the pipeline industry in general and exceeds that level in some areas.

4) The designation of two response zones (Hobbs and Sugar Land) and the locations of two response subcontractors based in Houston and other more distant areas, allows response time in the middle sections of the pipeline that is consistent with the industry.

5) Local fire departments outside of these areas are mostly volunteer departments and might lack the equipment and training to fight a HAZMAT fire.

6) There are sensitive environmental areas and special land use areas that do not have detailed response plans in the FRP.

7) Estimated maximum or worst case spill volumes were calculated at several selected locations. Most of these volumes fell within a range of about 3,000 to 6,000 bbl. However, a maximum release volume of 36,000 bbl was estimated at one location over the Cenozoic Pecos Aquifer.

5.8.12 Year 2000

1) No major Y2K risk issues were identified.

2) The pipeline operator has a Y2K plan and project in place.

3) The plan is complete and consistent with efforts in other industries, and with industry efforts as surveyed by the API.

4) The Y2K project is adhering to plan and is on schedule.

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